Decision 2003-077

EUB

Alberta Electric System Operator

2003 General Tariff Application (Phase I and Phase II) Negotiated Settlement and Unresolved Matters

November 4, 2003

Alberta Energy and Utilities Board

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ALBERTA ENERGY AND UTILITIES BOARD
Decision 2003-077: Alberta Electric System Operator
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Application No. 1290683

Published by
Alberta Energy and Utilities Board
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Contents

1 DECISION SUMMARY 1

2 INTRODUCTION 2

3 THE SETTLEMENT 3
- 3.1 Participation in Settlement 3
- 3.2 Details of the Settlement 5
- 3.3 Views of the Board 8
  - 3.3.1 Fairness of the Settlement Process 8
  - 3.3.2 Public Interest 9

4 UNRESOLVED ISSUES 10
- 4.1 Applicability of the COS Credit 10
  - 4.1.1 Background 10
  - 4.1.2 Views of AESO 13
  - 4.1.3 Views of TCE 14
  - 4.1.4 Views of IPCAA 15
  - 4.1.5 Views of the COS Coalition 17
  - 4.1.6 Views of CMH 19
  - 4.1.7 Views of BCH 19
  - 4.1.8 Views of FIRM 20
  - 4.1.9 Views of the Board 21
- 4.2 Fort Nelson Settlement 24
  - 4.2.1 Views of the AESO 24
  - 4.2.2 Views of BCH 25
  - 4.2.3 Views of Powerex 26
  - 4.2.4 Views of FIRM 27
  - 4.2.5 Views of the Board 28

5 OTHER MATTERS – AESO'S 2004 GTA 31

6 SUMMARY OF BOARD DIRECTIONS 32

7 ORDER 33

APPENDIX A – NEGOTIATED SETTLEMENT 35

Alberta Electric System Operator
2003 General Tariff Application (Phase I and Phase II)
Negotiated Settlement and Unresolved Matters

Decision 2003-077
Application No. 1290683
File No. 1808-01

1 DECISION SUMMARY

This Summary is provided for the benefit of the reader. All persons making use of this Summary are reminded that the remaining text of the Decision should be consulted for all purposes relating to the interpretation and application of the Board's decisions.

Having considered the terms of the Settlement in light of the requirements of the EUA and the Board's *Guidelines*, the Board finds that the Settlement reflects an overall balance of risk and rewards between the AESO and its customers. The Board does not consider that any element of the Settlement or the resulting tariff is patently contrary to the public interest. Indeed, the Board is satisfied that the Settlement will result in a tariff that is just and reasonable and in the public interest. Accordingly, the Board concludes that the Settlement should be approved in the amount of the adjusted[1] $734.3 million.

Although the Settlement proposes no change to the structure of the AESO's rates for 2003, which are essentially "rolled-over" from 2002, there were matters relating to COS Credits and the Fort Nelson Settlement issue that were outside the Negotiated Settlement that the Board was asked to rule on in this Decision.

In the Decision, the Board directed the AESO to continue to consider that all COS Credit payments made in 2002 and 2003 as well as the class of customers who are entitled to receive the Credit are to remain interim until the COS/COT Issues are fully considered and determined in the AESO's 2004 GTA, as per the existing approvals.

The Board has approved the inclusion of COS Credits for all eligible customers, including DAT and dual use customers (including ISDs), on an interim refundable basis, as to both amount and eligibility, based upon the guidelines set out above and to remit these Credits to eligible customers on a timely basis. All these matters are to be fully and finally addressed in the 2004 GTA.

With respect to the Fort Nelson Settlement, the Board accepts the AESO's response that, regardless of how the customer is characterized, no customer contribution is required. Accordingly, the Board agreed that no customer contribution is required in respect of the facilities that are subject to the Fort Nelson Settlement. However, the Board is not prepared to deal further with this issue, in this Decision, including the disposition of the Negotiated

[1] The Board notes the original revenue requirement applied for was $744.2 million while the amount agreed to in the settlement document of July 4, 2003 was $732.4 million. In the actual filing of July 14, 2003, this was adjusted to $734.3 million as a result of the Board's determinations in Decision 2003-054.

Settlement under the *Transmission Matters Deficiency Correction Regulation* and any eligibility of BC Hydro for COS Credits in isolation to all the other COS/COT issues already deferred to the 2004 GTA. The Board considers that all of these similar issues should be dealt with at one time.

With respect to the Liability Issues, the AESO applied separately for interim amendments to its Terms & Conditions of Service (T&Cs) (Liability Module).[2] The Board issued Decision 2003-059 on July 18, 2003, approving interim amendments to Article 14 of the AESO's T&Cs.[3] At the time of the present Decision, the Board is in the process of considering final argument and reply in the Liability Module and a separate decision in that Module will be issued in due course.

In order to facilitate an expedited decision on the 2004 administrative costs, the Board has directed the AESO to separate its 2004 General & Administrative (G&A) costs from the rest of the 2004 GTA in a filing to be made by December 1, 2003. The Board intends to issue its Decision on the 2004 G&A costs no later than January 31, 2004.

2 INTRODUCTION

On February 12, 2003, the Transmission Administrator of Alberta (TA), now known as the Alberta Electric System Operator (AESO), filed its 2003 General Tariff Application (GTA) consisting of both a Phase I and a Phase II. In the filing, the AESO noted that it did not make significant changes to the cost allocations, rate design, rate schedules or terms and conditions of service, which were approved by the Board in the AESO's 2002 tariff.

On February 28, 2003, the Board issued a Notice of Proceeding to the interested parties complete with a preliminary schedule for consideration of the GTA. On March 21, 2003, pursuant to the Board's *Revised Negotiated Settlement Guidelines, Tolls, Tariffs, and Terms And Conditions Of Service*, Informational Letter IL 98-04 (Revised) (*Guidelines*), the AESO applied to the Board for its consent to initiate settlement discussions in relation to the 2003 GTA. On March 25, 2003, the Board approved the AESO's request to initiate discussions with a view to reaching a negotiated settlement of the GTA. At the same time, the Board modified the process schedule to accommodate settlement discussions.

On July 14, 2003, the AESO filed a negotiated settlement (Settlement) with the Board and sought approval of the Settlement pursuant to section 134 of the *Electric Utilities Act*, SA 2003, c. E-5.1 (EUA). The AESO indicated that the Settlement addressed all but a specific list of issues, which were set out in Article 17 of the Settlement (Unresolved Issues), those being:

(a) The AESO's historic method used to determine eligibility of customer owned substation (COS) credits and issues, which concern the appropriate methodology and application of a prospective customer owned transmission (COT) credit (COS/COT Issues).

(b) The approval of the system access arrangements to the BC Border serving Fort Nelson, B.C. (WESCUP Arrangements).

[2] Application No. 1306252

[3] Decision 2003-059, Alberta Electric System Operator, 2003 General Tariff Application – Liability Protection: Part A: Interim Amendment to Article 14 (July 18, 2003)

(c) The scope of liability protection and/or indemnification provided to ancillary service providers and transmission facility owners (Liability Issues).

The AESO understood that parties would continue to pursue these issues either as part of the 2003 GTA process or some other process. The Settlement is reproduced in Appendix A to this Decision.

In light of the pressing nature of the Liability Issues, the AESO applied separately for interim amendments to its Terms & Conditions of Service (T&Cs) (Liability Module).[4] The Board issued Decision 2003-059 on July 18, 2003, approving interim amendments to Article 14 of the AESO's T&Cs.[5] At the time of the present Decision, the Board is in the process of considering final argument and reply in the Liability Module and a separate decision in that Module will be issued in due course.

In a letter dated July 21, 2003, in which the Board revised the schedule for review and consideration of the Settlement, the Board advised parties that the COS/COT Credit Issues and WESCUP Arrangements would be considered in the context of the 2003 GTA and Settlement. Accordingly, those issues are addressed in this Decision.

Prior to receipt of the Settlement, in accordance with the original schedule established for consideration of the GTA, the Board received responses to information requests from the AESO as well as written evidence from some interested parties, all of which form part of the record of the Board's consideration of the GTA and the Settlement.

In accordance with its July 21, 2003 letter, the Board received final Reply from interested parties by August 6, 2003. Accordingly, for purposes of this Decision, the Board considers the record to have closed on August 6, 2003.

3 THE SETTLEMENT

3.1 Participation in Settlement

In its Settlement filing, the AESO noted that, subsequent to parties executing the Settlement, the Board released Decision 2003-054, which relates to the Article 24 Refund Omnibus Proceeding.[6] In that Decision, the Board directed treatment of interest funds received by the AESO from Engage Energy Canada, L.P. that differs from the treatment reflected in Article 14 of the Settlement. Accordingly, the AESO included as part of the filing a revised Appendix 3 (revenue requirement spreadsheets, rate calculation sheets, and revised rate schedules) to reflect the treatment of interest funds established by the Board in Decision 2003-054. The AESO noted that the provisions of Article 14 allowed for this update, in the event the Board's decision differed from the AESO's proposed treatment of those interest funds.

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[4] Application No. 1306252

[5] Decision 2003-059, Alberta Electric System Operator, 2003 General Tariff Application – Liability Protection: Part A: Interim Amendment to Article 14 (July 18, 2003)

[6] Decision 2003-054, Alberta Electric System Operator, Aquila Networks Canada (Alberta) Ltd., and ATCO Electric Ltd., Article 24 Refund Omnibus Proceeding, Refund to AESO Customers, Refund to DISCO End-Use Customers (July 8, 2003)

The following parties executed the Settlement:

- AESO
- Alberta Urban Municipalities Association (AUMA)[7]
- Alberta Association Municipal Districts & Countries
- AltaGas Services Inc.
- AltaLink Management Ltd.
- ATCO Electric Ltd.
- ATCO Power Canada Ltd.
- EnCana Corporation
- ENMAX Corporation
- City of Calgary
- City of Red Deer
- TransCanada Energy Ltd.
- TransAlta Utilities Corporation
- City of Lethbridge
- Industrial Power Consumers Association of Alberta (IPCAA)[8]
- Public Institutional Consumers of Alberta
- Consumers Coalition of Alberta

The AESO indicated that the City of Medicine Hat (CMH), EPCOR Utilities Inc., the COS Coalition, and Powerex did not intend to sign the Settlement, but also did not intend to oppose Board approval of the Settlement. The AESO also indicated that it was not aware of any opposition to the Settlement from any other party.

As noted earlier, the Settlement addresses all Phase I and II matters arising from the AESO's 2003 GTA, except the Unresolved Matters. The Board will consider the Settlement itself in this Section and the Unresolved Matters in the subsequent Section of this Decision.

In the AESO's July 14, 2003, letter accompanying the Settlement, the AESO requested the following Orders from the Board pursuant to section 134 of the EUA:

(a) Approving the AESO's 2003 Phase 1 submission as set out in the GTA, as amended by the Settlement in its entirety, as the basis for the determination of the AESO's revenue requirement and charges for service for 2003.

(b) Approving the AESO's Phase II submission as set out in the GTA, as amended by the Settlement in its entirety, as the basis for the AESO's rates for the provision of system access service and T&Cs, with these rates and T&Cs becoming effective on the first day of the month after the Board approves them (pursuant to Article 2 of the T&Cs.)

(c) Such further and other Order or Orders as the Board may deem appropriate.

[7] AUMA was unable to sign the Settlement until well after the Settlement was submitted to the Board for approval. However, the Board did receive from the AESO a signature page on behalf of the AUMA on September 24, 2003.

[8] When the Settlement was executed, IPCAA was still known as the Industrial Power Consumers and Cogenerators Association of Alberta.

The parties specifically agreed in Clause 6(a) of the Settlement that the Board was requested to approve the Settlement in its entirety as contemplated by section 135 of the EUA.

3.2 Details of the Settlement[9]

Phase I

The Board notes the original revenue requirement applied for was $744.2 million while the amount agreed to in the settlement document of July 4, 2003, was $732.4 million. In the actual filing of July 14, 2003, this was adjusted to $734.3 million as a result of the Board's determinations in Decision 2003-054. A breakdown of this amount was provided by the AESO and is attached to this Decision as part of Appendix A. The AESO also provided the following details with respect to the revenue requirement at pages 3 through 5 of the Settlement document:[10]

1. **Wire Costs ($346.5 million):** The forecast of wires costs is based on the transmission facility owner tariff filings for 2003. The 2003 tariff amounts have been set out and compared to the 2002 approved revenue requirement in the ISO's 2003 GTA filing. The forecast estimate included in the 2003 GTA has been reduced by $6.1 million to reflect the cost of isolated generation embedded in the Wire Cost estimate amount.

2. **Ancillary Service Costs ($208.4 million):** The Ancillary Service Costs forecast are for the following services:

   (a) Operating Reserves: consisting of Regulating, Spinning and Supplemental Reserves;

   (b) Stand-by Operating Reserves: available to cover forced outages, as well as errors in load forecasting;

   (c) Under Frequency Mitigation: required if the system frequency drops below 59.5 Hz following a system disturbance

   (d) Transmission Must Run: required to be on-line and running at specific outputs in specific areas to ensure system security;

   (e) Fort Saskatchewan Load Shed: in the event of transmission line overloading occurs in the Fort Saskatchewan area, certain load held under interruptible contracts can be shed to relieve the overload condition;

   (f) Voltage Support: traditionally provided by TransAlta Utilities (TAU) hydro generators;

   (g) Remedial Action Schemes: required in order to restore and maintain power system frequency at acceptable levels following the loss of the BC interconnection during high power transfers;

[9] In the Settlement, the AESO is identified as the "ISO" or Independent System Operator, which is the statutory title conferred by the EUA.

[10] Adjusted to reflect deletion of the Engage settlement amount.

(h) Black Start: generators that have the capacity to start without an external power source are relied upon to initiate the black start process;

(i) Interruptible Load Remedial Action Schemes: required to enable the ISO to maximize the import capability of the Alberta-BC interconnection. In the event the BC tie trips concurrent with high levels of import, load must be shed quickly in Alberta to arrest the frequency decline. The ISO contracts for loads to automatically trip in these situations; and

(j) Ancillary Services from Poplar Hill Plant: which support the Grande Prairie area.

3. **System Losses ($142.7 million):** The forecast of system losses for 2003 is the difference between the Alberta Interconnected Electrical System (AIES) generation forecast, plus the imports less AIES load less exports. With the assistance of Parties to this Settlement, the AESO has identified an inconsistency in its losses methodology, which lead to the over-recovery for losses in the first half of 2003. The ISO will amend its methodology for 2004. Rider C, while ultimately to be dealt with in the deferral account reconciliation, will be used, on an interim basis, to adjust for the over-recovery in the remainder of 2003.

4. **Other Industry Costs ($16 million):** This forecast amount pertains to the ISO's portion of the costs of the System Controller, Balancing Pool, Regulatory Hearing costs and Western System Coordinating Council / North West Power Pool (WSCC/NWPP) membership costs. The Parties have agreed to reduce the applied-for 2003 GTA forecast estimate of Other Industry Costs by $3.5 million.

5. **ISO Costs ($20.6 million):** As described below, the ISO Costs include Administration Costs, Interest and Amortization Costs, ISO Transition Costs, and costs attributable to the TA Deficiency Correction Regulation. The amounts comprising the $20.6 million are as follows:

   (a) **Administrative Costs ($12.9 million):** The Parties acknowledge that the items described in Table 1 of the ISO's 2003 GTA represent the ISO's Administrative Cost categories. The Parties have agreed to reduce the total Administrative Costs forecast estimate shown in Table 1 to the 2003 GTA (at page 10 of the filed application) by $0.4 million. The TA ISO agrees that no internal costs of the TA ISO are or have been claimed as part of any hearing costs before the Board. Further, the TA ISO agrees that costs recovered from a regulatory proceeding will offset this category of the revenue requirement.

   The ISO notes that treatment of forecast application fees of $0.5 million was netted against specific Administrative Cost components: $0.2 million was netted against ISO Staff and Benefits, and $0.3 million was netted against Consultant costs.

   (b) **Interest and Amortization ($1.6 million):** No particular breakdown or content for these components was agreed to by the Parties.

   (c) **ISO Transition Costs ($1.2 million):** The ISO forecast of $1.2 million relates to the impending transition and creation of the ISO and combining the operations of the Power Pool of Alberta and the Transmission Administrator. The agreed upon forecast

amount will relate to costs incurred by the ISO for severance, special consulting needs, lease termination and relocation costs. Recovery by the ISO of these amounts does not in any way relate to or establish any form of precedent concerning customers concurring with the recovery of costs for the formation of the ISO and aggregation of the Power Pool of Alberta and Transmission Administrator functions.

(d) **TA Deficiency Correction Regulation Fee ($4.9 million):** The Parties acknowledge that fees attributable to the TA Deficiency Correction Regulation are costs mandated by way of legislation. Recovery by the ISO of these amounts does not in any way relate to or establish any form of precedent concerning customers concurring with the recovery of premiums paid on the purchase of utility assets.

Phase II

The Settlement proposes no change to the structure of the AESO's rates for 2003, which are essentially "rolled-over" from 2002.

The AESO indicated that the agreed to T&Cs were those approved by the Board pursuant to Decision 2002-087[11] and in effect for the year 2002, except for the following amendments:[12]

(a) Article 1: the definition of Application Fee has been corrected so that reference is made to Article 7 and not Article 1.

(b) Article 1: the definition of Eligible Person has been amended to include direct access customers. A consequential amendment has been made to reference Part 6 of the newly proclaimed *EUA*.

(c) Article 1: the definition of the ISO has been added and will refer to the trade name the AESO.

(d) Article 4: the wording of this Article has been modified to comply with Board Decision 2002-103.

(e) Article 11: Pursuant to Decision 2002-048, Article 11.11 has been deleted.

(f) Article 15.5: hydro units formerly listed in Table A to Appendix F of the Terms and Conditions of Service are now included in the body of the text of this Article.

(g) Article 15.6: Appendix E has been added to the T&Cs and referred to in this Article. Appendix E lists all regulated generating units included as Part 1 to the Schedule attached to the *Electric Utilities Act,* RSA 2000 c.E-5, which Schedule was repealed upon proclamation of the EUA on June 1, 2003.

(h) Article 24: the wording of this Article has been modified to comply with Board Decision 2002-103.

[11] Decision 2002-087, ESBI Alberta Ltd., 2002 Tariff Refiling (October 8, 2002)

[12] As noted in the Introduction, Article 14 was subsequently amended pursuant to Decision 2003-059.

(i) Throughout: the reference to the TA will be deleted and replaced with the AESO as defined in Article 1.

Other Matters
The Settlement acknowledges the parties' anticipation of the need for a full regulatory proceeding for the AESO's 2004 GTA.

The AESO also agreed that its 2004 GTA filing will include, for all revenue requirement line category amounts (including but not limited ISO Costs) and revenue offset categories, a description of the current level of actual costs incurred in 2002 and 2003, the AESO's forecast estimate of costs to be incurred in the remainder of 2003, a forecast estimate of costs to be incurred in 2004, and a description explaining any variance between 2002, 2003, and 2004 annual amounts. The Settlement obliges the AESO to initiate a public consultation process in advance of filing its 2004 GTA.

The Settlement provides for any party to the Settlement, other than the AESO, to elect on 30 days written notice to select an audit firm, to perform an audit in respect of the AESO's compliance with the specific terms of the Settlement for the year, as long as notice is received by the AESO within 120 days after the 2003 ISO Annual Report and financial results have been issued by the AESO.

The Settlement also requires the AESO, by August 30, 2003, to file an application for the reconciliation of its 2000, 2001, and 2002 deferral account balances. The Board has since received that application and it is being considered pursuant to a separate process.[13]

3.3 Views of the Board

The Board notes that most, but not all, parties interested in the AESO's 2003 GTA have executed the Settlement. However, as indicated by the AESO, those parties not signing the Settlement have not opposed the Board's approval of it.

Where a negotiated settlement is not unanimous, but is unopposed, the Board has held that it will treat the settlement as if it were unanimous.[14] Accordingly, the Board will apply the two-fold test established in Decision 2000-85, namely

(1) Whether the Settlement process was fair and in accordance with the Board's *Guidelines,* and

(2) Whether any aspect of the Settlement is patently contrary to the public interest.

3.3.1 Fairness of the Settlement Process

As noted above, the first question for the Board is whether the settlement process was fair and in accordance with the Board's *Guidelines*.

The Board notes that the AESO has engaged all stakeholder groups in the negotiation process and that the Board has issued proper notice respecting the process for addressing the GTA and

[13] Application No. 1313525
[14] Decision 2002-064, *ESBI Alberta Ltd., 2002 Tariff Application & Negotiated Settlement* (July 16, 2002), page 15.

the Settlement. In addition, the Board notes that all matters which could not be resolved in the context of the Settlement have been dealt with in submissions in the present proceeding (COS/COT Credit Issues and WESCUP Arrangements) or are being dealt with separately (Liability Issues).

In this case, pursuant to both the EUA and the *Guidelines*, the Board appointed a staff member to monitor the negotiating settlement process and to attend settlement meetings. Because the settlement discussions were conducted on a confidential basis, the Board has not been privy to any of the confidential discussions that took place among the participating parties. However, the Board has been advised by the appointed staff member that all interested parties were invited to participate and that the process was open, fair and inclusive.

The Board has also been advised that parties to the meetings made effective use of the process to deal with the high level of technical information associated with the 2003 GTA. Intervener groups availed themselves of technical experts to provide analysis and to assist them with their negotiations. In addition, the Board is advised that customers appeared to have explored all significant issues that would normally arise in a GTA. From the foregoing, the Board concludes that all parties had the opportunity to participate in the negotiation process in a meaningful manner.

In view of these considerations, the Board finds that the Settlement was arrived at fairly and in accordance with the *Guidelines*.

3.3.2 Public Interest

The second question for the Board is whether the Settlement contains elements that could produce rates or T&Cs that are not just and reasonable. As indicated above, expressions of support by interested parties are of considerable comfort to the Board in assessing the justness and reasonableness of the resulting tariff. As noted, the Board received no *bona fide* objections to the Settlement.

Having considered the terms of the Settlement in light of the requirements of the EUA and the Board's *Guidelines*, the Board finds that the Settlement reflects an overall balance of risk and rewards between the AESO and its customers. The Board does not consider that any element of the Settlement or the resulting tariff is patently contrary to the public interest. Indeed, the Board is satisfied that the Settlement will result in a tariff that is just and reasonable and in the public interest. Therefore, the Board concludes that the Settlement should be approved.

Accordingly, the Board approves the AESO's filing of July 14, 2003, whereby the 2003 revenue requirement was adjusted to $734.3 million as a result of the Board's determinations in Decision 2003-054.[15]

[15] The Board notes the original revenue requirement applied for was $744.2 million while the amount agreed to in the settlement document of July 4, 2003 was $732.4 million. In the actual filing of July 14, 2003, this was adjusted to $734.3 million as a result of the Board's determinations in Decision 2003-054.

4 UNRESOLVED ISSUES

4.1 Applicability of the COS Credit

4.1.1 Background

In its 1999/2000 GTA, the TA, the AESO's predecessor, requested approval of the COS Credit to compensate customers who own their own substations, the costs of which are not included in the tariff of transmission facility owners or the TA. The Board, in Decision 2000-01, approved the COS Credit and directed the TA to refile its GTA incorporating the Board's findings.[16]

When the TA refiled its GTA, it proposed to terminate the COS Credit for the period June 1-December 31, 2000, to redesign the Credit for Board approval as of January 1, 2001 and to retroactively apply the redesigned Credit back to June 1, 2000.

In Decision 2000-25,[17] the Board considered the TA's First Refiling of the 1999/2000 GTA and concluded that the TA's proposal would require the Board to review and vary Decision 2000-01, in which the COS Credit had been approved for the entire effective period of the TA's 1999/2000 tariff (i.e. to December 31, 2000). The Board could find no basis to vary the Decision and directed the TA to reincorporate the COS Credit in the Second Refiling directed by the Board in Decision 2000-25.

The TA refiled its 1999/2000 GTA a second time as directed by the Board. The Board approved the Second Refiling in Decision 2000-34.[18]

After Decision 2000-34 was issued, a disagreement arose between CMH and the TA over CMH's eligibility for the COS Credit,[19] which resulted in an application by CMH for review and variance of Decision 2000-34. CMH claimed that it was entitled to a Credit based on its contracted for DTS Billing Capacity and not on its "net contracted load" (i.e. net of STS capacity) as contended by the TA. In Decision 2000-64, the Board found that it was unnecessary to review Decision 2000-34 in this respect because it was clear that the COS Credit was to be based on DTS Billing Capacity.[20]

In its 2001 GTA, the TA proposed a modification of the COS Credit, which it called the Customer Owned Transmission Station (COT) Credit. While the Board considered that the proposal had merit, it was not persuaded that the COT Credit should be implemented immediately. Accordingly, in addressing 2001 GTA Phase 2 matters in Decision 2001-32, the Board directed the TA to continue to offer the COS Credit to the end of 2001 and to support the COT proposal with more comprehensive information in the TA's next GTA (i.e. 2002).[21]

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[16] Decision 2000-01, ESBI Alberta Ltd., 1999/2000 General Rate Application, Phase 1 and Phase 2 (February 2, 2000)

[17] Decision 2000-25, ESBI Alberta Ltd., 1999/2000 Tariff Application Refiling – Part B: Tariff and Terms and Conditions of Service (April 25, 2002)

[18] Decision 2000-34, ESBI Alberta Ltd., Phase I & II, 1999/2000 General Rate Application, Second Refiling (May 26, 2000)

[19] As well as the so-called Dual-Use Credit provided for in Article 9.13 of the TA's then approved T&Cs. The Dual-Use Credit is discussed more fully below.

[20] Decision 2000-64, ESBI Alberta Ltd., Application by the City of Medicine Hat for a Review and Variance of Decision 2000-34 re Net Contracted Load (October 5, 2000), page 3.

[21] Decision 2001-32, ESBI Alberta Ltd., 2001 General Tariff Application, Part H: Phase II Matters (May 2, 2001), pages 143-144.

Accordingly, the Board in Decision 2001-49 approved the COS Credit for 2001 as approved by the Board for 1999/2000.[22]

Prior to the TA's 2002 GTA, the TA applied to the Board for approval of a Duplication Avoidance Tariff (DAT) in relation to Shell Canada's Scotford Industrial System (Scotford DAT Application). One of the issues raised in the Scotford DAT Application was the eligibility of Shell for a COT Credit, since if Shell were to build Duplicate Facilities (rather than being the beneficiary of a DAT), it would be eligible for a customer-owned facility credit under the TA's 2001 tariff. In addressing this issue in Decision 2001-68, the Board said the following:[23]

> Clearly, when the Application was filed, it appears that EAL was working under the assumption that the Board would approve the proposed COT rate and that the COT rate would apply in the circumstances of bypass. However, the Board notes that the COT, including eligibility criteria, was not finally approved in EAL's 2001 Phase II Decision, Decision 2001-32. The Board further notes that certain directions, respecting COT, were given to EAL in that Decision and will be addressed in the 2002 GRA filing.
>
> As mentioned above, the final form of the COT has not been addressed. In particular, the issue has not been addressed whether bypass facilities would be eligible for any approved COT. The Board considers that there are a number of issues related to the qualification of bypass facilities for COT and the Board is not convinced at this time, that bypass facilities such as Shell Scotford should qualify for the COT. The Board considers that a final determination on this matter should be made at the time of hearing the 2002 GTA and all of the remaining COT issues.

The TA was able to negotiate a settlement of its 2002 GTA (2002 Settlement), which was approved by the Board in Decision 2002-064. Contrary to the Board's expectations as expressed in Decision 2001-68, the TA did not apply for a COT Credit as part of its 2002 GTA, nor did a COT Credit form part of the Settlement. However, Clause 21(j) of the 2002 Settlement provided as follows:

> For clarity, the COS Credit Rate Schedule shall be interim refundable as of January 1, 2002 pending a COT Credit application and approval by the Board.[24]

Following a Refiling of the TA's 2002 GTA, the Board approved the TA's 2002 tariff in Decision 2002-087.[25] The COS Credit Rate Schedule approved by the Board for 2002 was the same Schedule approved for 1999/2000 and 2001.[26]

In its 2003 GTA, the AESO indicated as follows with respect to the COS/COT Credit issues:[27]

> In Decision 2001-32 and Decision 2001-68, the Board gave directions to the Transmission Administrator for purposes of implementing the COT. Among these was a direction to provide COS credit for the remainder of 2001 to customers who own their

[22] Decision 2001-49, ESBI Alberta Ltd., 2001 General Tariff Application, Part K: Final Rates and Tariffs and Second Refiling (June 1, 2001).
[23] Decision 2001-68, ESBI Alberta Ltd., Duplication Avoidance Tariff Application Shell Scotford Industrial Site (August 9, 2001), pages 6-7.
[24] Decision 2002-064, page 23.
[25] Decision 2002-087, *ESBI Alberta Ltd., 2002 Tariff Refiling* (October 8, 2002).
[26] Decision 2002-087, Appendix B, page 13 of 34.
[27] 2003 GTA, Phase II, Tab B, Attachment 1 (Letter dated February 12, 2003).

own transmission facilities. In compliance, the Transmission Administrator continues to provide a COS credit to customers. To address emerging implementation issues, the Transmission Administrator proposes the following application guide for COS credits:

COS credits will not apply to customers who are contained within an ISD.

By virtue of providing transmission facilities, customers within an ISD are able to reduce transmission charges by presenting to the transmission system one or more points of delivery or supply that are net of aggregated local demands and supplies. Extending the COS credit to customers within an ISD would mean customers outside of the ISD would share in the cost of the transmission facilities within the ISD but would not receive any benefit from the offsetting revenue stream from the multiple points of delivery and supply inside the ISD.

COS credits will not apply to customers with both an STS and DTS contract at a single Point of Supply/Demand whenever the STS contract level exceeds the DTS contract level.

While new supply customers bear full responsibility for their own interconnection costs, new demand customers share the cost responsibility for interconnection costs with existing customers through the investment policy of the Transmission Administrator. The COS credit recognizes that demand customers who own facilities that are normally part of the transmission system reduce the revenue requirement of a transmission facility owner who would otherwise provide these facilities. Since most supply customers have DTS contracts to provide power for station service and start-up power the Transmission Administrator proposes that COS credits apply only where the DTS contract level exceeds the STS contract level. This will ensure that supply customers continue to bear the full cost responsibility of interconnection costs.

COS credits will not be based on the cost of installed customer facilities but on the cost of the facilities the TA would have put in to serve the customer.

Because the avoided costs to the transmission system are equal to the cost of the facilities the Transmission Administrator would have installed in the absence of the customer facilities, the COS credit should not be based on the cost of the installed customer facilities that may differ.

The Transmission Administrator is not proposing to implement a COT credit in 2003. As a result the Transmission Administrator believes that a review of the COT during the 2003 GTA would not be productive. Accordingly, the Transmission Administrator does not intend to address the remaining COT/COS implementation directives in its upcoming 2003 General Tariff Application. Instead we propose to address the remaining directives prior to proposing the implementation of a COT/COS credit and the stakeholders will be afforded the opportunity to test any proposal at a future hearing.

In the Settlement of the 2003 GTA, the parties agreed in Article 17(a) as follows in relation to the outstanding COS/COT Issues:

> 17. The Parties acknowledge the following issues are not the subject-matter of this Settlement and require adjudication by the Board:
>
> (a) The ISO's historic method used to determine eligibility of customer owned substation credits and issues which concern the appropriate methodology and

application of a prospective customer owned transmission credit ("COS/COT Issues").

Following filing of the Settlement, there was some disagreement about the scope of the COS/COT Issues to be addressed by the Board in the 2003 GTA. However, in its letter of July 21, 2003, the Board agreed with AESO that the only issue the Board would consider at the present time was as follows:

> ... the narrow issue of the applicability and eligibility of the COS rate as currently approved by the Board and as proposed for 2003. This would include the specific issue raised by the FIRM Group of whether a customer is eligible for a COS Credit where DTS and STS services are provided, and the specific issue raised by the COS Coalition of whether a DAT customer is eligible for a COS Credit.

The Board agreed that, with the exception of this narrow issue, all COS/COT Credit issues should be deferred until 2004, particularly since the evidentiary record did not yet appear to the Board to be sufficient. However, even with respect to the narrow issue, the Board reserved its right to determine that this issue should also be deferred until 2004.

4.1.2 Views of AESO

The AESO's understanding was that there were two narrow COS issues for consideration in this proceeding, namely whether DAT customers or customers who receive both STS and DTS service (i.e. dual-use customers) should be eligible to receive the COS Credit during the year 2003.

The AESO did not propose changes to the interim refundable nature of the COS Credit as approved by the Board for 2002, since final determinations by the Board may, and likely will, consider both the method by which the COS Credit should be determined as well as the class of customers who are entitled to receive the Credit.

With respect to the eligibility of DAT customers, the AESO agreed with the COS Coalition that DAT customers are similarly situated to other customers who are eligible for the COS Credit.[28] In the AESO's view, the COS Coalition's IR responses raised sufficient doubt as to whether Decision 2001-68 was intended to preclude DAT customers from being treated as eligible for the COS Credit.[29] In the result, AESO was prepared to support DAT customers being eligible for the COS Credit, particularly given that this Decision would only take effect on an interim basis.

The AESO also concurred with the views expressed by the COS Coalition that dual-use customers are entitled to COS Credits and emphasized that it was addressing occurrences wherein dual-use customers were not receiving the Credit. Again, the AESO's view was predicated on the interim refundable nature of the present COS Credit. This support did not extend to the level or amount of the Credit, as the AESO acknowledged that, pursuant to the direction from the Board provided in its July 21, 2003 letter, these issues would be explored in the 2004 GTA.

> The AESO was critical of FIRM, the COS Coalition and the arguments of others who provided views that the AESO considered to be beyond the scope of this proceeding,

[28] Written Direct Evidence of the COS Coalition date June 9, 2003 at pp. 15-18.
[29] See COS Coalition Responses to AESO-COS Coalition 02 and 03.

particularly on the need to finalize prior period COS Credit amounts. The AESO took the position that these matters would given due consideration in the 2004 GTA and, therefore, need not be considered in this proceeding. The AESO was particularly critical of the Coalition and CMH for failing to recognize that the COS Credit is approved and provided today on an interim refundable basis pursuant to Decision 2002-064.

The AESO considered the lack of evidence on the record relied on by the Coalition as a reason for finalizing the Credits to militate ***against*** finalizing them, in favour of their full consideration in the 2004 GTA. The AESO also submitted that the 13th month billing ratio issue, relied on by the Coalition, did not relate to the eligibility or applicability of the COS Credit for 2003. Concerns over the consideration of the billing ratio issue in this proceeding have been previously cited,[30] and based upon the limited record in this proceeding, the AESO noted that the Board ultimately determined that this issue falls outside the scope of argument and determinations to be made in this case.

The AESO suggested that the real cause of FIRM's concern over the increasing level of COS payments was the method used to calculate the COS Credit and whether prior period changes to the billing ratio should be implemented as a means to prevent the otherwise resulting increasing trend. The AESO maintained that the method of calculating the COS Credit was not related to the narrow issue of COS Credit applicability and eligibility for 2003 and, therefore, was beyond the scope of this proceeding. However, continuation of the interim refundable nature of the COS Credit would allow the issue to be fully considered at the 2004 GTA.

With respect to potential abuse of the COS Credit by dual-use customers, the AESO submitted that the interim refundable nature of the Credit has meant and means that all AESO customers should be fully aware that any COS Credit payment is subject to refund. The AESO submitted that the continued interim refundable nature of the COS Credit, pending finalization in the 2004 GTA, counters any real likelihood for potential abuse to occur, regardless of the eligibility criteria introduced. The AESO further maintained that its position that DAT and dual-use customers should be considered eligible for the COS Credit in 2003 had not been seriously challenged, other than with respect to whether these issues should be determined on a final basis or not.

4.1.3 Views of TCE

TCE submitted that when customers are willing to receive DTS and STS service through the same facilities, typically transformers and radial lines, the dual use of these facilities benefited the remainder of the system compared to building separate facilities to supply DTS and STS customers. To the extent that a DTS customer is paying for a share of the joint use facilities through the DTS tariff, TCE maintained that the customer should also be entitled to a COS Credit in cases where the facilities are not included in the AESO's rate base. To do otherwise would provide a disincentive for DTS and STS customers to work together to share facilities with the benefit of lowering transmission costs.

TCE also maintained that DAT customers should be eligible for a COS Credit. TCE acknowledged that it must first be established that the DAT customer has paid for customer owned facilities that qualify for a COS Credit (either in a direct payment or as part of the DAT calculation).

[30] See letter dated July 9, 2003, from Bryan & Company on behalf of CMH.

TCE disagreed with FIRM's further view that "facilities that are predominately required for supply service are receiving inappropriate credits," based on FIRM's view that "the level of STS demand is 5 times greater than DTS demands for these customers".[31] TCE claimed this statement conveyed a fundamental misunderstanding of the reasons why a customer is entitled to a COS Credit. Regardless of the use of a substation facility by a STS customer, the DTS customer continues to pay full demand charges for the use of the substation. According to the current DTS tariff, the DTS customer is charged on the highest of the 15-minute demand in the Billing Period, the ratchet level, or 90% of the Contract Capacity.[32] Every time a DTS customer uses DTS service, they trigger a DTS demand that, as a result of the Ratchet Level, will trigger demand-related costs for 5 years. If the Contract Capacity is unchanged over time, the DTS customer will pay at least 90% of the Contract Capacity as a demand-related charge. TCE submitted that as a consequence of this rate design, a DTS customer was paying for their local connection costs through the tariff. If they have also paid for their own substation, they are paying twice for this part of the transmission system that relates to local interconnection costs.

TCE also responded to FIRM's opposition to COS Credits where an Industrial System Designation (ISD) existed.[33] TCE explained if an ISD customer has one or more locations where it receives DTS service, the DTS tariff will apply at each substation location and the tariff will recover system costs that include the cost of a substation to supply the loads.

For the foregoing reasons, TCE submitted that a DTS customer should be eligible for a COS Credit where DTS and STS services are provided, including cases where an ISD exists.

Finally, with respect to the issue of whether the COS credits should be made final or remain interim, TCE was sympathetic to the concerns raised by the COS Coalition and CMH. While the AESO may see little problem in deferring the eligibility and levels for COS Credits for potentially three or four years, TCE submitted that these credits were not insignificant amounts to individual customers and can impact investment and ownership decisions. TCE therefore recommended that COS Credits be made final for 2002 and 2003.

4.1.4 Views of IPCAA

IPCAA considered that elimination of the COS Credit would create inconsistent treatment for dual-use customers who own their own substations and those that do not.

With respect to DAT customers, IPCAA noted that the Board decisions approving the DATs for Joffre, Scotford, and Cold Lake indicated that the terms of the DATs were designed to result in the proponent incurring the same costs under the DAT as they would have, had they constructed facilities that resulted in the customer presenting their net load to the system.[34] IPCAA submitted that this financial neutrality could only be maintained if a COS Credit is offered under the DAT if a COS Credit would have been offered had the physical facilities been constructed. If the physical facilities would have met the criteria for COS eligibility, then the DAT customer should be eligible for the COS Credit.

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[31] FIRM Argument, page 2
[32] Refer to Rate DTS set out in Board Decision 2002-087, Appendix B, page 3 of 34
[33] FIRM Argument, page 6
[34] Decision 2000-70 Page 4, Decision 2002-060, Page 23 and Decision 2002-019, Page 26

Responding to FIRM, IPCAA submitted that, for purposes of the COS Credit, the "period of time" a facility is utilized for STS or DTS was irrelevant. All customers taking DTS service pay a tariff that reflects "full service." The tariff charges related to transformation/substations do not vary with the period of time a substation is utilized for STS or DTS – the tariff component related to transformation/substations is a demand charge. This is the case regardless of the DTS customer's "utilization". The COS Credit is intended to compensate a customer who provides the transformation/substation utilized to provide them DTS service.

IPCAA noted FIRM's concern over the level of credit payments but submitted that FIRM ignored the fact that dual-use customers are paying the same DTS demand charges as all other DTS customers, despite the fact that the system is not incurring any costs related to substation investment to serve them. IPCAA explained that the "escalation" in costs merely reflected a correction from the earlier windfall arising from charging COS-eligible customers for facilities in relation to which the AESO saw no costs.

With respect to the eligibility of ISD customers, IPCAA acknowledged that AESO would receive more revenue if a dual-use customer were billed on a gross basis than a net basis, but considered this fact to be irrelevant. IPCAA noted that an ISD was not necessary to achieve billing on a net basis. A "behind the fence" generator can achieve the same netting without an ISD.

Responding to FIRM's proposal that, where STS demand was larger than DTS demand, the customer should not be eligible for any credit, IPCAA noted Decision 2001-06, pursuant to which dual-use customers are currently entitled to investment in facilities deemed to be required to provide the local facilities related to the DTS portion of their service. The application of the DTS/(DTS+STS) ratio to the customer related costs for a dual-use customer leads to a determination of the demand related costs for a dual-use installation. These costs are then compared against the roll-in ceiling to assess the need for a customer contribution (if any).[35]

IPCAA submitted that if the COS Credit is eliminated for some or all dual-use customers, it would be less attractive to own dual-use facilities and more attractive to have the system supply them. According to IPCAA, therefore, elimination of the Credit will not result in the customer being "economically indifferent as to whether a substation is provided by the system or by the customer."[36]

To provide for consistent treatment of dual-use customers with STS greater than DTS between those that own their own transformation/substations and those that do not, IPCAA would also require dual-use customers with STS greater than DTS to be disentitled to any investment in respect of the facilities required to provide their DTS service.

IPCAA agreed with CMH and the COS Coalition that it would be inappropriate, unfair, and contrary to sound regulatory principles for credits paid to customers as far back as January 2001 to be considered interim in 2004, three years later.

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[35] See TA Customer Contribution Guide: Scenario #6 New Generator & Load filed under TA letter to the Board of February 4, 2003

[36] In Decision 2000-25, the Board described its view as to the intent of the COS credit:
The Board agrees with EAL that the amount of the COS credit should be no more and no less than that required to keep the customer economically indifferent as to whether a substation is provided by the system or by the customer. (Decision 2000-25, p. 8 emphasis added)

4.1.5 Views of the COS Coalition

The COS Coalition made a number of recommendations as follows:

1. The AESO should be directed to apply the COS in a consistent manner as per the terms of the approved rate. Any AESO customer owning its own transmission substation (COS eligible) should qualify, regardless of whether they also are a part of an ISD, and/or are subject to a DAT.

2. The COS Credit rate of $700/MW/month did not require adjustment. The Coalition noted that this would roughly equate to a corresponding rate base (investment) of $56,000/MW while from the examples in the Customer Contribution Policy Guide,[37] the AESO was willing to invest a maximum of $73,500/MW for a DTS customer for the revenue-related amount.[38]

3. The COS billing determinant should continue to be the same as the DTS Billing Capacity, in all applications of COS. The Coalition provided an example which it claimed showed that that the type of customer (dual–use vs. pure load) should not be relevant to the determination of the COS billing determinant.[39] The Coalition claimed that the existing Customer Contribution Policy could accommodate dual-use customers and limited AESO investment to a level, which ensured that dual-use customers are treated equitably with pure supply customers and pure load customers. The COS billing determinant must be the same as the DTS demand billing determinant (Billing Capacity) to afford equality between different types of AESO customers.

4. In situations where existing Customer Assets are stranded, from the duplication of facilities, moving to dual-use or the installation of a transmission bypass, the AESO should perform a Customer Contribution Policy buydown calculation and charge the responsible customer the appropriate fee. Once this was done, the current Customer Contribution policy could be applied to any new costs. In the Coalition's view, the current Customer Contribution Policy was sufficiently robust to accommodate these situations and the COS billing determinant does not have to be adjusted. The Coalition further noted that the DTS energy charge is intended to recover deep, system related costs and does not impose any on-going cost responsibility on the customer. The reduced load factor from this customer does not result in increased system costs and, in fact, defers deep system upgrades, as the deep system now has spare capacity for other customers.

5. Customers with a Board-approved DAT should be eligible for COS. If any Customer Assets are stranded, the customer should be responsible for the costs in the same manner as any other AESO customer who partially strands a Customer Asset. The AESO should be directed to make an application to the Board for COS to be applied to customers who are COS eligible and are subject to a DAT, on an expedited basis. COS should be effective from the effective date of the DAT. The Coalition noted that customers that invested capital contributions in virtual bypasses did so under the key premise that the design of a DAT was to keep the customer involved financially neutral between

[37] Filed with the Board on February 3, 2003.
[38] Depending on the size of the DTS contract, the TA will also invest for contract terms longer than 5 years. For example, a 10 MW DTS customer willing to sign a 20 year contract would receive an additional investment of $60,000/MW.
[39] Direct Evidence of the COS Coalition, June 9, 2003, page 12.

physically building transmission assets and operating under a DAT. The COS eligibility issues have eroded this financial neutrality, and if not resolved, will lead to sub-optimal investment decisions, to the detriment of all AESO customers (and end-use electric energy consumers).

6. The AESO should comply with the Board's directives as soon as possible and provide the analysis for the development of a COT. This information should be shared with interested parties and the AESO should seek feedback. If appropriate, a revised COT should be filed by the AESO in its 2004 GTA.

7. The AESO should evaluate the need for a "13th month" adjustment as part of its response to all the COS/COT related Board directives and should make a proposal in its 2004 GTA.

8. The current COS rate should be made final for 2002 and 2003.

The Coalition noted that the COS rate schedule was made interim as a result of the 2002 negotiated settlement with the understanding that it would be replaced by a COT credit as soon as practically possible.[40] The Coalition considered the 2003 GTA proceeding to be appropriate for the AESO to provide its proposals with respect to COT, or any changes to COS.

The Coalition requested that the Board grant final approval for 2002 and 2003 of the AESO COS rate pending subsequent application (if any) by the AESO to amend that rate or to replace that rate with a COT rate. The Coalition also submitted that the Board should direct the AESO to apply Board approved rates in a consistent manner to all customers who are eligible.

The Coalition also recommended that the COS rate be applied to all dual-use DAT customers who would otherwise qualify for the credit. The Coalition stated the TA should be directed to make an application to the Board for COS to be applied to customers who are COS eligible and are subject to a DAT, on an expedited basis. COS should be effective from the effective date of the DAT.

The Coalition was critical of FIRM for a number of reasons. Responding to FIRM's suggestion that dual-use customers are getting something for nothing, the Coalition noted the direct correlation between the quantum of COS Credits paid out and the reductions to TFO's rate bases resulting from customer investments in transmission substations. Additionally, the AESO was also now appropriately paying the COS credit to customers who were qualified, but were not previously receiving the credit.

The Coalition also argued that ISD customers should be eligible for the COS Credit. The Coalition maintained that the "economically indifferent" test, which was fully incorporated into the AESO's 2003 tariff, ensured that the cost of transmission facilities to an ISD were no different from the costs of transmission facilities to any other customers who can legally, or with the AESO's permission, totalize multiple points of delivery and supply, or own transmission assets.

[40] Decision 2002-64, page 10

Finally, the Coalition submitted that the definition and determination of a customer who is eligible for a rate is inherent within the rate and cannot be determined by a business practice, which may or may not be contained in the T&C.

4.1.6 Views of CMH

On the basis that the terms of the COS Credit for 2003 remain as previously approved by the Board, the City of Medicine Hat (CMH) considered that it remained eligible to receive the Credit.

CMH considered the AESO's suggestion that this rate is interim refundable for both 2002 and 2003 to be incorrect and the source of unnecessary uncertainty for customers who have, in good faith, made energy purchase decisions from the AIES based on the understanding that DTS Service and the COS Credit are both based on DTS Billing Capacity. Any material adjustment to the COS Credit, occurring at this late date, would constitute unnecessary retroactive ratemaking. CMH suggested that all COS/COT credit issues should be deferred to 2004 and that the existing COS rate be made final.

CMH noted FIRM's concern with the "increasing level of COS Credits,[41] but characterized it as nothing more than a reflection of the increasing dependence of the AESO on customer-supplied facilities that provide a benefit to the AIES. CMH disagreed with FIRM's view that dual-use customers were receiving "inappropriate credits" because STS demand exceeds DTS demand.

CMH maintained that to effect changes to the COS rate now would be inappropriate and not what was contemplated by the Board when it issued Decision 2001-32. The COS rate should be made final for 2002 and 2003.

4.1.7 Views of BCH

For the following reasons, BC Hydro (BCH) disagreed with FIRM's view that since service to the Fort Nelson Point of Delivery and Point of Service constitutes a net supply service, BCH should be ineligible for COS Credit, and should be directed to refund interim refundable credits from prior periods:

- BCH concurred with TCE that DTS customers should receive all of the benefits and privileges available in the tariff that are associated with the obligation to pay the DTS tariff. Since June 2000, BCH has had a bona fide DTS contract with the TA, now the AESO. Being the owner of a substation not included in the AESO's rate base, BCH, as a DTS customer, was entitled to a COS Credit in accordance with the COS Rate;

- Even in the event that BCH may be considered a dual-use customer at the Fort Nelson Delivery Point, a characterization that BCH disputed, the Board has confirmed that the COS Credit and the Dual-use Credit are two separate credits, largely independent of each other, such that a customer may be eligible for either or both.

- As noted by CMH, the Board has been clear that the COS Credit received by an eligible customer is to be determined on the basis of Billing Capacity, not on the basis of any "net contract level".

[41] Argument, page 4

Finally, BCH agreed with the COS Coalition as to whether the 2002 and 2003 COS Credit ought to be affirmed on an interim or permanent basis. However, BCH added that, if the Board concluded that the COS rates for 2002 and 2003 are and should remain interim and refundable, a refund order in late 2004 or 2005 could cause significant financial impact on affected parties given the significant lapsed time.

4.1.8 Views of FIRM

In argument, FIRM noted the principle established in Decision 2000-1 that the responsibility for local connection costs for DTS customers is shared between the customer and the AESO while local connection costs for STS customers are borne 100% by these customers.

FIRM submitted that, where usage is strictly DTS or strictly STS, the treatment is straightforward. However, where a customer has a single connection to the system and utilizes it for both DTS and STS services, the customer is effectively a dual-use customer. Furthermore, where such a customer provides its own substation that is utilized for DTS and STS service, credit eligibility is an issue. Conceptually for the period of time when the substation is utilized for DTS service a COS credit could apply. Similarly, for the period of time when the substation is utilized for STS service no credit should apply.

FIRM supported the AESO's application for a business practice where "COS credits will not apply to customers with both an STS and DTS contract at a single Point of Supply/Demand whenever the STS contract level exceeds the DTS contract level." FIRM disagreed with the AESO's suggested deferral of the institution of this practice.

FIRM also supported the AESO's proposed business practice for 2003 where "COS credits will not apply to customers who are contained within an ISD." FIRM disagreed with the AESO's suggested deferral of the institution of this practice. FIRM agreed with the AESO that "Extending the COS credit to customers within an ISD would mean customers outside of the ISD would share in the cost of the transmission facilities within the ISD but would not receive any benefit from the offsetting revenue stream from the multiple points of delivery and supply inside the ISD." Therefore, FIRM submitted that the proposed business practice should be implemented and any prior COS Credits refunded to the AESO.

FIRM submitted that the AESO and the Board have previously recognized the issue and it is only through AESO non-compliance with prior Board directives that it remains an issue for the 2003 GTA. Because of the increasing level of these credits, FIRM submitted that the eligibility and applicability of these credits must be addressed in a timely fashion in this GTA, largely due to what it termed the rapidly rising cost of the credits without a commensurate benefit.

FIRM was critical of the AESO for supporting the eligibility of DAT customers. FIRM submitted that Board directive 2001-68.1 explicitly referenced the issues that must be addressed by the AESO to determine whether bypass facilities would qualify for any COT Credit and the terms and conditions that would need to apply. As COS is simply a subset of COT, FIRM submitted that the AESO had not addressed any of the issues in the directive and, therefore, there was no basis to extend eligibility to DAT customers at this time.

FIRM was also critical of the AESO for supporting the eligibility of dual-use customers. FIRM submitted the AESO had not provided any support for this change of position and a non-

conditioned eligibility assured that supply customers would not bear full cost responsibility, contrary to the principle of the tariff.

FIRM disagreed with the COS Coalition's assertion that applying the ratio to the COS rate was not warranted. In FIRM's view, the Coalition evidence did not refute the fact that STS customers bear 100% cost responsibility for connection costs. Therefore, non-application of the ratio to a dual-use customer simply provides the STS service with a "free ride" and results in increased costs for the remaining AESO customers.

FIRM also disagreed with the Coalition's assertion that a 13th month adjustment was not necessary, noting that, since STS does not have a demand charge, but only an energy charge, there is no required discipline in the STS contract quantity. FIRM considered the Board to have recognized this concern in Decision 2000-32 and correctly suggested that the AESO implement a 13th month billing procedure.

FIRM rejected the Coalition's request that the COS be made final. The COS rate should be finalized as long as the associated business practices for eligibility and applicability ensure the full COS Credit is only available to single-use DTS customers. In FIRM's view, dual-use customers must be subject to a reduced level commensurate with their STS contractual quantities. FIRM submitted that there was sufficient evidence on the record to apply the net contracted load criterion or the DTS/STS+DTS ratio to ensure equitable treatment. However, if the Board finds there is insufficient evidence, FIRM submitted that the COS Credit must remain interim to ensure equitable treatment for AESO customers in the future. Eligibility should not be expanded at this time pending resolution of the issue.

With respect to the argument of CMH, FIRM submitted that the Board has approved the net contracted load criterion[42] for dual-use customers and it is straightforward to apply this calculation to the COS Credit. FIRM noted the Board's previous indication that only that "portion" of demand capacity, which exceeds supply capacity, should be eligible.

FIRM maintained that other AESO customers are currently prejudiced by the AESO including excessive levels of COS credits for dual-use customers in the revenue requirement. Furthermore, the suggestion that any adjustment to the COS Credit would constitute unnecessary retroactive ratemaking is without basis. The issue has been well known to customers with the outstanding Board directives and the Board decision that the COS rate should be interim refundable.

4.1.9 Views of the Board

As noted in the Background to the COS/COT Issues, the Board ruled that it would only consider the following issue in the context of the AESO's 2003 GTA:

> ...the narrow issue of the applicability and eligibility of the COS rate as currently approved by the Board and as proposed for 2003. This would include the specific issue raised by the FIRM Group of whether a customer is eligible for a COS Credit where DTS and STS services are provided, and the specific issue raised by the COS Coalition of whether a DAT customer is eligible for a COS Credit.

[42] FIRM Argument at page 10, also Board Decision 2000-64

However, the Board expressly reserved its right to determine that even this narrow issue should be deferred until 2004.[43]

As matters presently stand, the AESO's 2002 GTA includes the COS Credit Rate Schedule approved in Decision 2002-087, which otherwise approved the AESO's 2002 tariff on a final basis, but left the COS Credit Rate Schedule "interim refundable" pending approval of a COT Credit by the Board, as agreed to by the AESO's predecessor and customers in the 2002 Settlement. The Board notes that the AESO did not propose changes to the interim refundable nature of the COS Credit as approved by the Board for 2002, since the AESO noted that final determinations by the Board may, and likely will, consider both the method by which the COS Credit should be determined as well as the class of customers who are entitled to receive the Credit.

However, the Board agrees with the AESO that whether 2002 and 2003 COS Credit payments ought to be made final or left on an interim basis was not intended to form part of the narrow issue to be addressed, if at all, in this proceeding.

Accordingly, the Board directs the AESO to continue to treat all COS Credit payments made in 2002 and 2003, as well as the class of customers who are entitled to receive the Credits as being interim until the COS/COT Issues are fully considered and determined in the AESO's 2004 GTA.

With respect to the eligibility of DAT customers, the Board notes that the AESO agreed with the COS Coalition that DAT customers are similarly situated to other customers who are eligible for the COS Credit.[44] In the AESO's view, the COS Coalition's IR responses raised sufficient doubt as to whether Decision 2001-68 was intended to preclude DAT customers from being treated as eligible for the COS Credit.[45] In the result, the AESO was prepared to support DAT customers being eligible for the COS Credit, particularly given that this Decision would only take effect on an interim basis.

The AESO also concurred with the views expressed by the COS Coalition that dual-use customers are entitled to COS Credits and emphasized that it was addressing occurrences wherein dual-use customers were not receiving the Credit. Again, the AESO's view was predicated on the interim refundable nature of the present COS Credit.

With respect to the eligibility of dual-use and DAT customers, in principle, the Board is of the view that a customer should only have to pay once for the cost of transmission facilities for which the customer is responsible. To the extent that a customer owns and has paid for its own facilities, but continues to pay for these facilities a second time through demand charges in the AESO's DTS rate, the Board considers that the customer may be entitled to a certain level of offsetting compensation through eligibility for the COS Credit. Accordingly, the Board is willing to accept the views of the AESO that both DAT and dual-use customers, including ISD customers, should be eligible for COS Credits in 2002 and 2003, on an interim refundable basis, as to both Credit amount and eligibility.

[43] Although not expressly included in the scope of this "narrow issue", ISD customers are effectively a subcategory of dual-use customers, which the AESO considered in the 2003 GTA itself to be ineligible for the COS Credit.
[44] Written Direct Evidence of the COS Coalition date June 9, 2003 at pp. 15-18.
[45] See COS Coalition Responses to AESO-COS Coalition 02 and 03.

With respect to DAT customers, the Board notes that the primary purpose of a DAT is to offer a customer a rate or rates sufficiently attractive so as to make the customer financially indifferent between remaining on the system and building the Bypass Facilities in question. However, since customer indifference will vary according to the particular circumstances, the Board is of the view that the eligibility of DAT customers must be examined on a case-by-case basis so that the amount of the Credit, if any, should only be that necessary to maintain the economic indifference of the customer.

However, the Board does not presently have enough evidence on the record of this proceeding to determine and approve the COS Credit amounts that should be payable to DAT Customers in accordance with the views just expressed. Accordingly, the Board directs the AESO, in its 2004 GTA, to address the eligibility of DAT customers on a case-by-case basis so that the amount of the Credit, if any, should only be that necessary to maintain the economic indifference of the customer.

The AESO suggested that the real cause of FIRM's concern over the increasing level of COS payments was the method used to calculate the COS Credit and whether prior period changes to the billing ratio should be implemented as a means to prevent the otherwise resulting increasing trend. The AESO maintained that the method of calculating the COS Credit was not related to the narrow issue of COS Credit applicability and eligibility for 2003 and, therefore, was beyond the scope of this proceeding. However, continuation of the interim refundable nature of the COS Credit would allow the issue to be fully considered at the 2004 GTA.

With respect to potential abuse of the COS Credit by dual-use customers, the AESO submitted that the interim refundable nature of the Credit has meant and means that all AESO customers should be fully aware that any COS Credit payment is subject to refund. The AESO submitted that the continued interim refundable nature of the COS Credit, pending finalization in the 2004 GTA, counters any real likelihood for potential abuse to occur, regardless of the eligibility criteria introduced. The AESO further maintained that its position that DAT and dual-use customers should be considered eligible for the COS Credit in 2003 had not been seriously challenged, other than with respect to whether these issues should be determined on a final basis or not.

Given the interim nature of customer eligibility for 2002 and 2003, the Board does not consider that it is necessary or appropriate to make a determination in relation to FIRM's proposal. Accordingly, for purposes of this Decision, the Board rejects FIRM's proposal that the STS/(STS+DTS) ratio, applied in the AESO's customer contribution policy in accordance with Article 9 of its T&Cs, be applied to the COS Credit as well.

On the basis of these conclusions, the Board directs the AESO to calculate COS Credits for all eligible customers including DAT and dual use customers (including ISD), on an interim refundable basis as to both amount and eligibility, based upon the guidelines set out above and to remit these Credits to eligible customers on a timely basis. All these matters are to be fully addressed in the 2004 GTA. Further, the Board directs the AESO to report on the payments made to eligible customers pursuant to this Decision in the AESO's 2004 GTA.

4.2 Fort Nelson Settlement

4.2.1 Views of the AESO

The AESO explained that, pursuant to an Electric Service Agreement (ESA) entered into by Alberta Power Limited with Westcoast Energy Inc/Canadian Utilities Limited (WESCUP) on August 10, 1990, ATCO Electric Ltd. (AE) was required to construct and install certain transmission facilities in order to provide WESCUP with electric service to the British Columbia/Alberta border. In return, WESCUP agreed to pay AE for all services provided under the ESA in accordance with AE's tariffs as approved. WESCUP agreed to provide BCH with electric service via a separate Power Purchase Agreement. The ESA was signed for a term of 20 years, expiring on August 10, 2010.[46] BCH subsequently requested System Access Service from the TA. The TA proposed to meet BCH's request by providing DTS in exchange for the payment to the TA of the DTS tariff.

As part of this 2003 GTA, the AESO filed for Board approval of the Negotiated Settlement Agreement reached between the TA and AE (Fort Nelson Settlement).[47] The AESO stated that this filing complied with the Board's directives from Decision 2001-32.[48]

The AESO noted that FIRM had raised several questions in this proceeding about the Fort Nelson Settlement.[49] One issue concerned why a customer with STS of 40 MW and DTS of 24.5 MW would be deemed a load customer only and the supply component of 40 MW ignored. As noted in the AESO's Response to FIRM-TA-17, the Board's directive addressed circumstances arising in the June/July 2000 timeframe. At that time, the deemed customer was the load customer pursuant to the TA's then prevailing Customer Contribution Policy.

The AESO acknowledged that under the current Customer Contribution Policy, the ratio of the DTS contract capacity to the sum of the DTS plus STS contract capacities would be used to determine the capital costs to which the roll-in ceiling would apply. The AESO submitted that it was reasonable for it to apply the Customer Contribution Policy prevailing at the time the Fort Nelson Settlement was reached, as opposed to the Policy in place today. The AESO maintained that to do otherwise would provide little, if any, certainty to customers as to the amounts they should be obligated to pay in respect of customer contributions.

However, under that Policy and at that time, AESO submitted it was both reasonable and appropriate for the Customer Contribution Policy to be applied by giving consideration only to the DTS contract level. The AESO considered this approach to be consistent with Board Decision 2000-1, in which the Board specifically noted the following with respect to the TA's proposed Contribution Policy for Load Customers:

> The Board agrees with TransAlta that the contract level of the load seeking connection should drive the investment policy.[50]

[46] See FIRM-TA 16(a).
[47] See TA correspondence dated February 21, 2003.
[48] As noted in its Response to FIRM-TA 16 (Attachment A) the TA had previously filed the settlement with the Board on July 17, 2000.
[49] See FIRM-TA 16-18
[50] Decision 2000-1, page 271

Even if BCH/Powerex ought to have been characterized as a dual-use customer, which the AESO did not agree with in these circumstances, then consideration of the then prevailing method to calculate the dual-use credit would be necessary. At that time, the AESO submitted that the dual-use customer credit was calculated using only 75% of the available capital credit. Applying this calculation to the circumstances would still not result in a contribution from BCH/Powerex.[51]

The AESO noted that Decision 2000-64 clarified how net contracted load should prospectively be factored into the dual-use credit calculation and resulted in an amendment to paragraph 9.13 of the TA's tariff. However, this Decision took effect on October 5, 2000, some 3-4 months after the agreements had been entered into with BCH/Powerex.

As a result, AESO maintained that the issue properly boiled down to which was more reasonable:

- to apply the Customer Contribution Policy existing at the time the Fort Nelson Settlement was reached between the TA and AE, or

- to now (a) recharacterize BCH/Powerex as a dual-use customer and (b) apply a tariff amendment which took effect subsequent to the date in which commercial relations were entered into between the parties.

The AESO considered the second alternative to be unreasonable as it created significant uncertainty to parties seeking to enter into commercial relations with the AESO.

4.2.2 Views of BCH

BCH supported the AESO's request for approval of the Fort Nelson Settlement. BCH noted that at the commencement of the original arrangement, WESCUP made an initial capital contribution towards the construction of the ATCO Facilities of $782,000.00. In 1991, the Public Utilities Board (PUB) found that WESCUP was an Alberta customer (since it effectively took delivery of electric energy in Alberta), and determined that an Alberta company arranging out-of-province sales should pay a fair rate that reflects the incremental cost burden to Alberta customers and provide a fair return towards fixed costs to ensure that other Alberta customers do not subsidize the transaction. In 1993, the PUB approved ATCO's proposal to charge a monthly special facilities charge to WESCUP with respect to the ATCO Facilities. The monthly facilities charge was intended to recover the capital cost of the ATCO Facilities in order to ensure that Alberta ratepayers did not subsidize the cost of the ATCO Facilities.

BCH purchased the BC Facilities from WESCUP in February of 1999 and applied directly to the TA for System Access Service. By that time, the ATCO Facilities (and the BC Facilities) had been built and had been operating solely to serve load for approximately 9 years. The TA proposed to serve BCH as a DTS customer, which raised certain issues for ATCO. Thereafter, the TA provided BCH with DTS at a contract capacity of 24.5 MW effective June 1, 2000. No new facilities were constructed to accommodate this service. ATCO's revenue requirement was

[51] As noted in AESO's response to Board Directive 2001-32.30, the available capital credit was $4.9 million, seventy-five percent of which is $3.675 million. This amount is greater than the $3.1 million book value of the transmission line.

no longer reduced by the amount of the monthly facilities charge it was no longer receiving, but the TA instead began receiving payment from BCH in respect of the DTS it was providing.

BCH claimed that, on the basis of BCH taking DTS service for at least 7 years, the TA expected to recover the entire undepreciated capital cost of the ATCO Facilities through its DTS revenue stream. In light of the foregoing, BCH submitted that the Fort Nelson Settlement ought to be approved and the TA's 3-year old decision regarding the need for a customer contribution from BCH ought to be affirmed. That decision was properly made on the basis of the then prevailing tariff, the earlier decisions of the PUB regarding the ATCO Facilities, and the fact that the ATCO Facilities were built to serve load some 9 years earlier.

Moreover, BCH maintained that there was no evidence to suggest that there were any local connection or other facilities costs associated with the Fort Nelson Settlement, that there were any incremental costs arising from conversion to DTS service, or that costs associated with the ATCO Facilities have been shifted to Alberta customers. Instead, the evidence is that the AESO is satisfied that in light of BCH's DTS obligations, the undepreciated capital cost of the ATCO Facilities will be covered by the DTS charges.

BCH noted FIRM's argument that BCH/Powerex should be treated as one customer, contracting for both DTS and STS service, and should be compelled to pay a customer contribution. BCH acknowledged that, while it and Powerex were affiliated companies, each had its own Board of Directors, management, and legal personality. Each is a separate and distinct customer of the AESO eligible for, and in receipt of, system access service independent of the other. There was no evidence, in BCH's view, from which one could infer that Powerex and BCH are in law responsible for each other's obligations.

In particular, at the time BCH applied for DTS and in the specific context of BCH's application for DTS, there was no basis upon which the distinction between BCH and Powerex could fairly have been ignored by the AESO. In these circumstances, BCH maintained it would be manifestly unfair to re-visit that application after the fact, and to ignore the distinction in legal personality to which BCH and Powerex are generally entitled under the law.

It followed, therefore, that BCH was not a dual-use customer, that DTS and STS contract amounts should not be netted, that the allocation of a customer contribution to BCH was not supportable in the circumstances, and that the AESO's decision in this regard ought to be upheld, according to BCH.

4.2.3 Views of Powerex

Powerex argued that it was not responsible for a customer contribution with respect to the commencement of STS service in June 2000 for the simple reason that no local interconnection costs were incurred by the TA when the service was established. Powerex noted that its request for STS service, on lines built some 9 years earlier to serve load, did not require the construction, addition or upgrade of transmission facilities in order to satisfy the request.

Powerex shared BCH's view that BCH and Powerex should not be treated as a single dual-use customer at the Alberta/BC border. Although Powerex is an affiliate of BCH, it is a distinct corporation with its own Board or Directors, management structure, and legal personality. Powerex noted that it was a customer of the AESO, distinct and separate from BCH. There was

no evidence on the record to support the proposition implicit in the FIRM submission that Powerex and BCH are responsible for each other's obligations. In particular, at the time Powerex contracted for STS there was no basis upon which the distinction between Powerex and BCH could be ignored in the specific context of Powerex's application. As such, Powerex submitted that FIRM's assertion that Powerex ought to be responsible for any customer contribution that may be required of BCH with respect to the ATCO Facilities should be rejected.

4.2.4 Views of FIRM

FIRM claimed that the AESO's delay in addressing this issue had deprived the other AESO customers of a customer contribution from BCH/Powerex, dating back to June 2000.

FIRM considered it clear that there is a single Point of Supply (POS) and Point of Demand (POD) at the Alberta/BC border serving to interconnect the BCH/Powerex supply of 40.0 MW and the demand of 24.5 MW. Therefore, FIRM submitted that BCH/Powerex was a dual-use customer at the common POS/POD at the provincial border. Furthermore there was nothing in the AESO application to support BCH and its 100% affiliate, Powerex, from not being treated as a single dual-use customer at the provincial border. FIRM further noted that Decision 2000-34 explicitly stated that the Rate Schedules and associated Terms and Conditions (T&C) included in the Decision were effective June 1, 2000. FIRM submitted that the T&C govern the impact of the Settlement among the AESO and BCH/Powerex.

FIRM disagreed with the AESO's view, expressed in response to Board directive 2001-32-30, that the deemed customer would be the load for purposes of applying the Customer Contribution Policy. FIRM submitted that in the circumstances of the BCH/Powerex dual-use of local transmission facilities for both STS and DTS services, the resulting "net contracted load" criterion is zero, since STS capacity exceeded DTS capacity.

FIRM noted that in Decision 2000-64,at page 11, the Board clarified 9.13 of the TA's T&C as follows:

> 9.13 Dual-use customers that have not previously received a capital credit in respect of their interconnection costs are eligible for a dual-use credit.
>
> A dual-use customer that receives a credit under Rate Schedule COS and that has not previously received a capital credit in respect of the dual-use customer's interconnection costs is eligible for a credit calculated using 75% of the values in the table in paragraph 9.3 applied to the net contracted load of the dual-use customer.
>
> A dual-use customer that does not receive a credit under Rate Schedule COS and that has not previously received a capital credit in respect of the dual-use customer's interconnection costs is eligible for a credit calculated using the values in the table in paragraph 9.3 applied to the net contracted load of the dual-use customer.

FIRM acknowledged that while the revised wording for Article 9.13 conditioned the level of capital credit available depending on whether the customer receives a COS Credit, the overriding condition of net contracted load remained. Therefore, FIRM considered it immaterial to the availability of the capital credit whether or not BCH/Powerex received a COS Credit. The net contracted load criterion indicated that the capital credit should be zero. FIRM maintained that

the total of the customer-related connection costs, $3.1 million in the BCH/Powerex case, less a zero capital credit, should be paid as a customer contribution.

FIRM also noted Article 9.5 of the approved T&C provided that "The TA will not provide a capital credit for transmission facilities required to provide System Access Service under Rate Schedules STS, DOS, Import Service and Export Service." In FIRM's view, in the Fort Nelson Settlement circumstances, local transmission facilities are necessary to provide STS service and, on a contractual basis, these STS service levels are greater than the DTS levels. Therefore, FIRM submitted that Article 9.5 of the AESO's T&C also precluded applying a capital credit for transmission facilities that are STS-related.

Finally, FIRM noted the AESO's response to Directive 2001-32.31 that past payments should not be taken into account by the Board and BCH/Powerex should be treated as a new customer. FIRM noted that a new customer should be subject to the Customer Contribution Policy provisions and a customer contribution was clearly required.

4.2.5 Views of the Board

As noted above, the issues surrounding the Fort Nelson Settlement were originally raised by FIRM in the context of Phase II of the TA's 1999/2000 GTA. In Decision 2001-32, the Board said the following about the Settlement:

> The Board considers that any agreement, which affects the regulated revenue requirement of the TA, and consequently the rates charged to Alberta customers of the TA, is a matter requiring consideration by the Board pursuant to its jurisdiction to set just and reasonable rates under the EU Act.
>
> In addition, in the Board's view, the matters covered by the Settlement are clearly issues arising from the implementation of EAL's currently approved 2000 Tariff. They are matters relating to the TA and the transmission system. As such they are "issues" as that term is defined in section 64 of the EU Act that relate to a matter within the ordinary jurisdiction of the Board (i.e. the approval of the just and reasonable rates of the TA). Accordingly, the Board has the jurisdiction to approve the negotiated settlement of any such issue pursuant to section 67 of the EU Act and may take the settlement into account in consideration a tariff application pursuant to section 50 of the Act.
> In the Board's view, the settlement of an issue within the Board's jurisdiction, particularly one having a potential impact on the rates to be charged to other customers, can be reviewed and approved by the Board.
>
> Therefore, the Board directs EAL to file with the Board an application for approval of the Fort Nelson Settlement in EAL's 2002 tariff application.
>
> Also, the Board directs EAL to calculate and file with the Board examples of what the customer contribution, if any, would be required, given a $3,100,000 transmission line cost (per Exhibit 66) for each of the following situations for customer(s) located on the Alberta side of the BC-Alberta border as follows:
>
> 1. A customer with a DTS only load of 24.5 MW
> 2. A customer with both a STS supply of 40.0 MW and a DTS load of 24.5 MW
> 3. A customer with a STS supply of 40.0 MW and an affiliate located on the same premises with a DTS load of 24.5 MW

> Further, the Board directs EAL, in its application for approval of the Settlement, to address whether the past payments should be given any consideration in the Board's decision. EAL should also address whether the interprovincial aspect of these circumstances should be considered by the Board and, if so, how. EAL should provide any examples of similar past or current interprovincial situations.
>
> Following its review of the Settlement and the associated evidence, the Board will determine the amount of customer contribution, if any, to be assessed against BCH after all evidence in the directed approval process has been heard and considered.[52]

As the TA noted in the original application for approval of the Settlement, the Settlement is, in effect, a contract of a term longer than 5 years that required approval under the *Transmission Matters Deficiency Correction Regulation*, AR 150/2000 (TMDC Regulation), which was in force at the material time.[53] In some respects, it is also a negotiated settlement of a transmission-related issue as contemplated by the relevant provisions of the EUA, as noted by the Board in Decision 2001-32.

The Board notes that the actual facilities in question were constructed prior to 1991. The ESA, pursuant to which the facilities were constructed, was executed on August 10, 1990, five years prior to the enactment of the first *Electric Utilities Act*,[54] which initiated the process of deregulation in Alberta. It was pursuant to the Old EUA that the TA was created and became statutorily obliged to provide System Access Service. It was also pursuant to the Old EUA that the TA became the sole provider of System Access Service, so that anyone wishing to exchange energy through the Alberta power pool was required to contract with the TA for that Service. BCH purchased the BC Facilities from WESCUP in February of 1999 and, owing to the requirements of the Old EUA, applied directly to the TA for System Access Service.

The Board notes that the Fort Nelson Settlement was reached in mid-2000. The Board further notes that all parties agree that the T&Cs in force at that time should govern the determination of any customer contribution due from BCH. The Board agrees that it would be unreasonable to apply tariff provisions retroactively to determine whether any customer contribution may be payable by BCH in the circumstances.

The Board notes, however, that FIRM considers the relevant T&Cs to be those approved in Decision 2000-64, which dealt with the CMH request to review and vary Decision 2000-34. The AESO considers that the T&Cs finalized in Decision 2000-34 should prevail. The Board notes that Decision 2000-34 approved the TA's Second Refiling and finalized rates for 1999/2000.

Decision 2000-34 was effective June 1, 2000, while Decision 2000-64 was not issued until later that year. However, the latter Decision did not result in a variation of the TA's 1999/2000 tariff, including T&Cs. Rather, the Board concluded that the intent of Article 9 of the TA's T&Cs, as approved finally in Decision 2000-34, was that the so-called Dual-Use Credit should be based on net contracted load. Since that was the intent of the approved T&Cs, the Board saw no reason to vary Article 9 as urged by CMH. Nevertheless, the effect of Decision 2000-64 was to clarify that Dual-Use Credits under the TA's then prevailing customer contribution policy should be based

[52] Decision 2001-32, pages 191-192.
[53] The *TMDC Regulation* was later repealed and replaced by Part 4 of the *Deficiency Correction Regulation, 2002*, AR 53/2002, which in turn was repealed by section 167(a) of the EUA on June 1, 2003.
[54] As amended in 1998 (Old EUA)

on net contracted load. In the Board's view, this clarification necessarily relates back to the effective date of the TA's final tariff, or June 1, 2000. In different circumstances, the Board considers that it might be bound to apply the terms of the 1999/2000 tariff in effect on June 1, 2000, as clarified by Decision 2000-64, notwithstanding that the latter Decision was issued after the execution of the Settlement.

In the Board's view, however, it is unnecessary to answer this question in the present circumstances, which the Board finds to be unique and unlikely to recur. The Board finds as a fact that the facilities were constructed in 1990 to serve load at the BC/Alberta border. At that time, WESCUP was clearly a load customer and there was no POS at the same point as WESCUP's POD. As indicated by BCH, at the time it applied to the TA for DTS, the facilities had been exclusively serving load for 9 years. When Powerex also applied for STS service at the same time, no new facilities were required and no further local connection costs were incurred.

In the Board's view, these circumstances militate against any consideration that a further contribution from BCH be required as of June 1, 2000, when it contracted with the TA for System Access Service, regardless of whether the applicable T&Cs are the "unclarified" T&Cs in place as of June 1, 2000 by virtue of Decision 2000-34, or the T&Cs "clarified" by Decision 2000-64.

The Board notes the AESO responded to the Board's previous directions as follows:

1. Given a transmission line cost of $3,100,000 and a DTS only load of 24.5 MW no customer contribution will be required. The TA's 1999/2000 GIS/GSS (or DTS) tariff allows for a customer investment of up to $200,000 per MW for each MW of contract capacity based on a contract term of 10 years. Therefore 24.5 MW of contract capacity would allow for a customer investment of $4,900,00,0, which is greater than the cost of the transmission line.
2. A customer with both a STS supply of 40.0 MW and a DTS load of 24.5 MW would also not pay a contribution since the deemed customer was the load and therefore the calculation of the customer contribution would be the same as (1) above.
3. For a customer with a STS supply of 40.0 MW and affiliate located on the same premises with a DTS load of 24.5 MW there would be no required customer contribution as in (2) above.

The Board accepts the AESO's response that, regardless of how the customer is characterized, no customer contribution is required. Accordingly, the Board agrees that no customer contribution is required for the Fort Nelson settlement.

Therefore, the Board sees no need to address FIRM's assertion that BCH and Powerex must be treated as one customer of the AESO such that they would be considered a dual-use customer under Article 9 of the T&Cs.

The Board notes that the AESO has applied to the Board, pursuant to the Transmission Matters Deficiency Correction Regulation, Alta. Reg. 150/2000, for an order binding future transmission administrators to the attached 20-year Transmission Facilities Services Agreement dated July 2000 (the "Fort Nelson Negotiated Settlement") between the Transmission Administrator and ATCO Electric Limited.

The Board is not prepared to deal further with this issue and the eligibility for COS credit in isolation to all the other COS issues already deferred to the 2004 GTA. The Board considers that all of these similar issues should be dealt with at one time. The Board considers that the AESO did not clearly indicate in support of its request for approval how the revenues from the BCH/Powerex tariffs compare to its financial obligations to AE. If the AESO wishes to have the Board deal with its request for approval of the Negotiated Settlement, it is able to re-apply as part of the 2004 GTA.

5 OTHER MATTERS – AESO'S 2004 GTA

Although not specifically addressed by any party, the Board is concerned about the timing of approval of the AESO's 2003 Tariff at this late point in the year. Given customer concerns respecting the certainty of tariffs for future years and the imposition of rate riders to recover costs from previous years, the Board considers that, wherever possible, a decision respecting Phase I of the AESO's tariff should be made prior to the commencement of the applicable year.

The Board considers that the approval process for the AESO's Own Costs should be improved so the Board's decision is issued much earlier in the year in question. The AESO's Own Costs include Administration Costs, Interest and Amortization Costs, AESO Transition Costs, and costs attributable to the TA Deficiency Correction Regulation. These amounts comprised $20.6 million in 2003. The Board's preference would be to deal with the entire tariff application prior to the commencement of that year. However, given that the Board recognizes that this is not likely possible, the Board is of the view that it is appropriate, particularly given the AESO's non-profit status, at the very least to decide matters with respect to the AESO's Own Costs as close to the beginning of the applicable year as possible.

Accordingly, the Board directs the AESO to separate its 2004 AESO's Own Costs from the rest of the 2004 GTA so that the Board and parties can deal with the G&A portion expeditiously. Further, the Board directs the AESO to file this portion of the 2004 GTA by December 1, 2003 (2004 AESO's Own Costs Application). The Board considers that approval by the AESO Board of Directors should be made prior to the 2004 AESO's Own Costs Application and provided as support for the Application in its filing. The Board will be sending out a process letter and draft schedule within 2 days of the release of this Decision for this upcoming proceeding.

The Board would encourage the AESO to anticipate the likely issues that interveners might have and to fully address these issues in their 2004 AESO's Own Costs Application to reduce the need for IRs. The Board is not opposed to a negotiated settlement for the AESO's Own Costs, but any settlement process for the these Costs should be separate from any settlement discussion of remaining Phase I costs. Any negotiated settlement submitted to the Board for approval should not result in delayed consideration of this aspect of the AESO's 2004 tariff.

While the Board wishes to finalize the AESO's Own Costs component of the AESO's 2004 GTA as early as possible in 2004, the Board intends to strive for consideration of the AESO's complete Phase 1 GTA for future years (2005 and beyond) in such a manner that the complete Phase 1 application is approved prior to the commencement of the applicable year. To this end, the Board directs the AESO prepare and file by January 31, 2004, its proposal for a process, which can achieve this goal.

6 SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. In view of these considerations, the Board finds that the Settlement was arrived at fairly and in accordance with the *Guidelines*. 9
2. Accordingly, the Board approves the AESO's filing of July 14, 2003, whereby the 2003 revenue requirement was adjusted to $734.3 million as a result of the Board's determinations in Decision 2003-054. 9
3. Accordingly, the Board directs the AESO to continue to treat all COS Credit payments made in 2002 and 2003, as well as the class of customers who are entitled to receive the Credits as being interim until the COS/COT Issues are fully considered and determined in the AESO's 2004 GTA. 22
4. However, the Board does not presently have enough evidence on the record of this proceeding to determine and approve the COS Credit amounts that should be payable to DAT Customers in accordance with the views just expressed. Accordingly, the Board directs the AESO, in its 2004 GTA, to address the eligibility of DAT customers on a case-by-case basis so that the amount of the Credit, if any, should only be that necessary to maintain the economic indifference of the customer. 23
5. On the basis of these conclusions, the Board directs the AESO to calculate COS Credits for all eligible customers including DAT and dual use customers (including ISD), on an interim refundable basis as to both amount and eligibility, based upon the guidelines set out above and to remit these Credits to eligible customers on a timely basis. All these matters are to be fully addressed in the 2004 GTA. Further, the Board directs the AESO to report on the payments made to eligible customers pursuant to this Decision in the AESO's 2004 GTA.. 23
6. Accordingly, the Board directs the AESO to separate its 2004 AESO's Own Costs from the rest of the 2004 GTA so that the Board and parties can deal with the G&A portion expeditiously. Further, the Board directs the AESO to file this portion of the 2004 GTA by December 1, 2003 (2004 AESO's Own Costs Application). The Board considers that approval by the AESO Board of Directors should be made prior to the 2004 AESO's Own Costs Application and provided as support for the Application in its filing. The Board will be sending out a process letter and draft schedule within 2 days of the release of this Decision for this upcoming proceeding. 31
7. While the Board wishes to finalize the AESO's Own Costs component of the AESO's 2004 GTA as early as possible in 2004, the Board intends to strive for consideration of the AESO's complete Phase 1 GTA for future years (2005 and beyond) in such a manner that the complete Phase 1 application is approved prior to the commencement of the applicable year. To this end, the Board directs the AESO prepare and file by January 31, 2004, its proposal for a process, which can achieve this goal. 31

7 ORDER

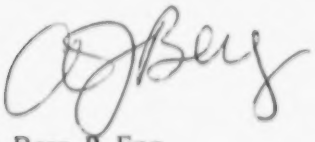
For and subject to the reasons and directions set out in this Decision, IT IS HEREBY ORDERED THAT:

(1) The Settlement attached as Appendix A to this Decision is approved.

(2) Dual-use (including ISD) and DAT customers are eligible for COS Credits in 2002 and 2003, on an interim refundable basis, in accordance with this Decision.

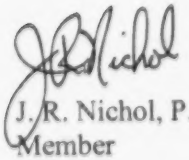
Dated in Calgary, Alberta on November 4, 2003.

ALBERTA ENERGY AND UTILITIES BOARD



A. J. Berg, P. Eng.
Presiding Member

R. G. Lock, P. Eng.
Member



J. R. Nichol, P. Eng.
Member

APPENDIX A – NEGOTIATED SETTLEMENT

"2003-07-14_AESO_
2003 Negotiated Sett

(Consists of 220 pages)

"2003-07-14_AESO_
APPENDIX 3 Revised

(Consists of 2 pages)

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APPENDIX 3 Revised

(Consists of 1 page)

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APPENDIX 3 Revised

(Consists of 5 pages)

2003

ALBERTA ELECTRIC SYSTEM OPERATOR

Negotiated Settlement Agreement

Dated July 4, 2003

TABLE OF CONTENTS

Page

2003 ISO Negotiated Settlement Agreement

I. INTRODUCTION 1

II. PRINCIPLES OF THE NEGOTIATED SETTLEMENT 2
- A. Phase I Issues 2
- B. Phase II Issues 5
- C. Other Matters: 2004 GTA & ISO Deferral Account Reconciliation 6
- D. Other Matters: Stakeholders' Right to Audit 7
- E. Other Matters: Financial 8
- F. Miscellaneous 8

APPENDIX 1: 2003 ISO Terms and Conditions of Service

APPENDIX 2: 2003 ISO Terms and Conditions of Service (Blackline)

APPENDIX 3: Revised Total Revenue Requirement
Revised Attachment 7 (Phase II) to the 2003 General Tariff Application
Revised Attachment 10 (Phase II) 2003 Tariff Rate Schedules

APPENDIX 4: 2004 GTA Stakeholder Issues

JUNE 2003

INDEPENDENT SYSTEM OPERATOR

Terms of the 2003 Negotiated Settlement

I. INTRODUCTION

In consideration of the mutual covenants set out in this agreement, the parties hereto agree as follows:

1. The Independent System Operator ("ISO") operating under the trade name of the Alberta Electric System Operator (the "AESO") and stakeholders who are signatories to this agreement (the "Stakeholders"), (collectively, the "Parties") have been successful in reaching a negotiated settlement (the "Settlement") of some but not all issues concerning the ISO's 2003 General Tariff Application ("GTA").

2. Except for the issues specifically described in paragraph 17 (the "Unresolved Issues"), Parties agree not to raise, argue, or otherwise dispute any other issues during the remaining regulatory process established by the Alberta Energy and Utilities Board ("Board") to consider the ISO's 2003 GTA.

3. The Parties acknowledge and agree to have the Board adjudicate upon the Unresolved Issues. No term of this settlement shall in any way preclude Parties from making submissions to the Board in respect of the Unresolved Issues, provided however, Parties shall not take any steps to add to the Unresolved Issues or in any way take steps that directly or indirectly advocate changes, amendments or variations to any of the terms of this Settlement.

4. The Parties acknowledge that although there is unanimous support among the Parties for the overall Settlement, as set out herein, there may not be unanimous support for any one cost component on a stand-alone basis. On a global basis, it is specifically acknowledged that there is no agreement on separate line items or any one cost component, except as specifically provided herein. The terms of the Settlement reflect a "package deal" and, therefore it is not possible for the Alberta Energy and Utilities Board ("Board") to accept any parts of the Settlement or impose any conditions on the Settlement, and still reflect the overall agreement reached as between the Parties. Thus if the Board does not accept the Settlement there shall be no settlement among the Parties of the issues to which the Settlement addresses and the Parties hereto will have the option to litigate all or any such issues before the Board.

5. It is understood and agreed by the Parties that information provided and settlement offers made among the Parties during the negotiation settlement process were exchanged and discussed on a confidential and without prejudice basis and remain confidential and shall not be disclosed, introduced or relied upon in any future proceeding or for any other purpose subject to the representations given in paragraph 35, herein.

6. The Parties specifically acknowledge that the terms of the Settlement are the result of broad industry negotiations and represent a balance of interests among the Parties. As there have been concessions made by all of the Parties, the Parties agree that:

   (a) the Settlement must be approved by the Board in its entirety, as contemplated in s. 135 of the *Electric Utilities Act*, S.A. 2003 c. E-5.1 (the "*EUA*");

   (b) if the Board does not accept the Settlement in its entirety; attempts to change the Settlement in any way; attempts to impose any terms or conditions on any approval of the Settlement; or approves the Settlement in a manner that materially impacts the ISO's revenue requirement for 2003, the Parties are released from the Settlement, with the exception of paragraph 5, above;

   (c) notwithstanding any other provision contained in this Settlement, the Settlement sets no precedent on any particular or individual issue in any future proceeding or forum and does not preclude or prejudice the rights of the Parties to pursue any issues of concern to them, including, without limitation, definitions, cost components, Board directives or deferral account reconciliation, in any proceeding in respect of 2003 or any future year;

   (d) for greater certainty, the Parties acknowledge that acceptance of this Settlement shall in no way be construed as agreement with or acceptance of the ISO's compliance with Board directives as contained in the materials filed by the ISO as part of the 2003 GTA process; and

   (e) the implementation of this Settlement will require Board approval.

7. The ISO will file this Settlement with the Board and request the Board's approval of the Settlement, in its entirety, as filed. By signing this Settlement, the Parties are supportive of the application to approve this Settlement. The revenue requirement, rates and terms and conditions of service applied for in the ISO's 2003 GTA, as modified by this Settlement and as modified by the Board in respect of any adjudication of the Unresolved Issues, shall in any event be effective upon Board approval and continue in effect for the year 2003 and until such time as the Board approves rates applied for in the 2004 GTA filing. Any differences in charges that arise before the ISO's 2004 GTA is approved by the Board will be included and recovered through use of the ISO's deferral accounts.

II. PRINCIPLES OF THE NEGOTIATED SETTLEMENT

A. Phase I Issues

8. The specific amounts, line items and provisions of the Phase I items are not agreed to nor detailed in this Settlement, with the exception of those items listed below.

9. All amounts described in the 2003 GTA and in this Settlement are understood to be the ISO's best estimate of forecast costs to be incurred for service to be provided in 2003. Notwithstanding, all actual amounts incurred by the ISO will be subject to deferral account treatment. Any difference between the 2003 forecast revenue requirement and

the actual costs incurred by the ISO in 2003 shall be recovered in rates charged by the ISO in 2004.

10. The ISO's revenue requirement commencing January 1, 2003 and specific to 2003 is amended to be $ 732.4 million. This amount is comprised of Wire Costs, Ancillary Service Costs, Losses, Other Industry Costs and the ISO's Costs as discussed below.

11. Wire Costs ($346.5 million): The forecast of wires costs is based on the transmission facility owner tariff filings for 2003. The 2003 tariff amounts have been set out and compared to the 2002 approved revenue requirement in the ISO's 2003 GTA filing. The forecast estimate included in the 2003 GTA has been reduced by $6.1 million to reflect the cost of isolated generation embedded in the Wire Cost estimate amount.

12. Ancillary Service Costs ($208.4 million): The Ancillary Service Costs forecast are for the following services:

    (a) Operating Reserves: consisting of Regulating, Spinning and Supplemental Reserves;

    (b) Stand-by Operating Reserves: available to cover forced outages, as well as errors in load forecasting;

    (c) Under Frequency Mitigation: required if the system frequency drops below 59.5 Hz following a system disturbance

    (d) Transmission Must Run: required to be on-line and running at specific outputs in specific areas to ensure system security;

    (e) Fort Saskatchewan Load Shed: in the event of transmission line overloading occurs in the Fort Saskatchewan area, certain load held under interruptible contracts can be shed to relieve the overload condition;

    (f) Voltage Support: traditionally provided by TransAlta Utilities ("TAU") hydro generators;

    (g) Remedial Action Schemes: required in order to restore and maintain power system frequency at acceptable levels following the loss of the BC interconnection during high power transfers;

    (h) Black Start: generators that have the capacity to start without an external power source are relied upon to initiated the black start process;

    (i) Interruptible Load Remedial Action Schemes: required to enable the ISO to maximize the import capability of the Alberta-BC interconnection. In the event the B.C. tie trips concurrent with high levels of import, load must be shed quickly in Alberta to arrest the frequency decline. The ISO contracts for loads to automatically trip in these situations; and

    (j) Ancillary Services from Poplar Hill Plant: which support the Grande Prairie area.

13. System Losses ($142.7 million): The forecast of system losses for 2003 is the difference between the Alberta Interconnected Electrical System ("AIES") generation forecast plus imports less AIES load less exports. With the assistance of Parties to this Settlement, the AESO has identified an inconsistency in its losses methodology which lead to the over-recovery for losses in the first half of 2003. The ISO will amend its methodology for 2004. Rider C, while ultimately to be dealt with in the deferral account reconciliation, will be used, on an interim basis, to adjust for the over-recovery in the remainder of 2003.

14. Engage Settlement Refund Adjustment ($1.9 million): The 2003 forecast revenue requirement has been reduced by this amount. The ISO will apply the Engage Settlement Refund to rate payers in the manner described in its application to the Board dated May 12, 2003 or as otherwise determined by the Board in proceedings concerning that application. For greater certainty, the 2003 forecast revenue requirement is subject to adjustments arising from the Board's adjudication of the ISO's May 12, 2003 application, including, but not limited to, the treatment of interest payments related to the Engage Settlement Refund.

15. Other Industry Costs ($16 million): This forecast amount pertains to the ISO's portion of the costs of the System Controller, Balancing Pool, Regulatory Hearing costs and Western System Coordinating Council / North West Power Pool ("WSCC/NWPP") membership costs. The Parties have agreed to reduce the applied-for 2003 GTA forecast estimate of Other Industry Costs by $3.5 million.

16. ISO Costs ($20.6 million): As described below, the ISO Costs include Administration Costs, Interest and Amortization Costs, ISO Transition Costs, and costs attributable to the TA Deficiency Correction Regulation.

    (a) Administrative Costs ($12.9 million): The Parties acknowledge that the items described in Table 1 of the ISO's 2003 GTA represent the ISO's Administrative Cost categories. The Parties have agreed to reduce the total Administrative Costs forecast estimate shown in Table 1 to the 2003 GTA (at page 10 of the filed application) by $0.4 million. The ISO agrees that no internal costs of the ISO are or have been claimed as part of any hearing costs before the Board. Further, the ISO agrees that costs recovered from a regulatory proceeding will offset this category of the revenue requirement.

    The ISO notes that treatment of forecast application fees of $0.5 million was netted against specific Administrative Cost components: $0.2 million was netted against ISO Staff and Benefits, and $0.3 million was netted against Consultant costs.

    (b) Interest and Amortization ($1.6 million): No particular breakdown or content for these components was agreed to by the Parties.

    (c) ISO Transition Costs ($1.2 million): The ISO forecast of $1.2 million relates to the impending transition and creation of the ISO and combining the operations of the Power Pool of Alberta and the Transmission Administrator. The agreed upon forecast amount will relate to costs incurred by the ISO for severance, special consulting needs, lease termination and relocation costs. Recovery by the ISO of

these amounts does not in any way relate to or establish any form of precedent concerning customers concurring with the recovery of costs for the formation of the ISO and aggregation of the Power Pool of Alberta and Transmission Administrator functions.

(d) TA Deficiency Correction Regulation Fee ($4.9 million): The Parties acknowledge that fees attributable to the TA Deficiency Correction Regulation are costs mandated by way of legislation. Recovery by the ISO of these amounts does not in any way relate to or establish any form of precedent concerning customers concurring with the recovery of premiums paid on the purchase of utility assets.

B. Phase II Issues

17. The Parties acknowledge the following issues are not the subject-matter of this Settlement and require adjudication by the Board:

(a) The ISO's historic method used to determine eligibility of customer owned substation credits and issues which concern the appropriate methodology and application of a prospective customer owned transmission credit ("COS/COT Issues").

(b) The approval of the system access arrangements to the B.C. Border serving Fort Nelson, B.C. (the 'WESCUP" arrangements).

(c) The scope of liability protection and/or indemnification provided to ancillary service providers and transmission facility owners.

18. The Tariff Terms and Conditions of Service attached as Appendix 1 shall govern the service offered by the ISO. The ISO acknowledges that the Appendix 1 Terms and Conditions of Service are those approved by the Board pursuant to Decision 2002-087 and in effect for the year 2002, except for the following amendments:

(a) Article 1: the definition of Application Fee has been corrected so that reference is made to Article 7 and not Article 1.

(b) Article 1: the definition of Eligible Person has been amended to include direct access customers. A consequential amendment has been made to reference Part 6 of the newly proclaimed *EUA*.

(c) Article 1: the definition of the ISO has been added and refers to the trade name the AESO.

(d) Article 4: the wording of this Article has been modified to comply with Board Decision 2002-103.

(e) Article 11: Pursuant to Decision 2002-048, Article 11.11 has been deleted.

(f) Article 15.5: hydro units formerly listed in Table A to Appendix F of the Terms and Conditions of Service are now included in the body of the text of this Article.

(g) Article 15.6: Appendix E has been added to the Terms and Conditions of Service and referred to in this Article. Appendix E lists all regulated generating units included as Part 1 to the Scheduled attached to the *Electric Utilities Act* RSA 2000 c.E-5 which Schedule was repealed upon proclamation of the *EUA*.

(h) Article 24: the wording of this Article has been modified to comply with Board Decision 2002-103.

(i) Throughout: the reference to the TA will be deleted and replaced with the AESO as defined in Article 1.

19. Appendix 2 to this Settlement provides a black-line comparison of the Terms and Conditions of Service approved pursuant to Decision 2002-087 and those to take effect pursuant to this Settlement and as found in Appendix 1.

20. The terms of this Settlement have required revisions to the ISO's applied-for total revenue requirement and to its 2003 Tariff Rate Calculations (Attachments 7 and 10 to the 2003 GTA). Revisions outlining these changes are attached as Appendix 3. The ISO acknowledges that the billing determinants for STS rates used in Appendix 3 take into account the Wabumun 3 facilities.

C. Other Matters: 2004 GTA & ISO Deferral Account Reconciliation

21. The ISO agrees that its 2004 GTA filing will include for all revenue requirement line category amounts (including but not limited ISO Costs) and revenue offset categories, a description of the current level of actual costs incurred in 2002 and 2003, the ISO's forecast estimate of costs to be incurred in the remainder of 2003, a forecast estimate of costs to be incurred in 2004, and a description explaining any variance between 2002, 2003 and 2004 annual amounts.

22. At this time, the Stakeholders anticipate the need for public regulatory proceedings into the 2004 GTA filing. Specifically, Stakeholders have identified the need for a detailed review of the cost components comprising the ISO's Phase I revenue requirement. As a result, the ISO agrees not to unilaterally promote or advocate a position that would preclude the Board from convening public hearings into the 2004 GTA filing, other than with the support of the Stakeholders.

23. In advance of the ISO filing its 2004 GTA with the Board, the ISO will convene a public consultation process with Parties. The purpose of this process will be to identify and discuss issues of concern, understand Stakeholders perspectives with respect to the priority of issues identified, and, where consensus can be achieved, resolve issues of concern to the Parties. Issues that have been identified to date for consultation are listed in Appendix 4 to this Settlement. The Parties do not intend Appendix 4 to be an exhaustive list of issues, nor do the issues listed reflect any form of agreed-to priority of importance. Notwithstanding the foregoing, the ISO's commitment to consult with Parties shall in no way constitute a delegation of or be construed in any way as a

limitation or restriction to the manner in which the ISO manages its affairs, including, without limitation, decisions respecting the incurrence of costs to conduct the functions and responsibilities of the ISO.

24. The ISO agrees to provide Parties with a detailed reconciliation of the 2000-2001 annual deferral accounts by July 4, 2003. A detailed reconciliation of 2002 deferral accounts will be provided by July 30, 2003.

25. By no later than August 30, 2003, the ISO agrees to file with the Board for its approval reconciliation of the deferral account balances for the years 2000, 2001 and 2002 (the "Bundled Application"). The appropriate methodology used by the ISO to reconcile the 2003 deferral account balances may also be raised by Parties as an issue for the Board to determine in any proceeding established to consider the Bundled Application. Specifically, Parties may seek to clarify the manner in which Riders B and C are to be applied to the deferral account reconciliation methodology for 2003 as well as any arising changes related thereto. Parties acknowledge and agree that any Board decision that concerns the method used by the ISO to reconcile 2003 deferral accounts may impact and cause amendments to the revenue requirement and rates as set forth in this Settlement. Parties further acknowledge and agree that any Board decision that concerns the Engage Settlement proceeding may also cause amendments to the revenue requirement and rates set forth in this Settlement.

26. Notwithstanding the foregoing and for greater certainty, the accounting treatment for Rider D will be taken into account in the 2003 deferral account reconciliation as if the rate associated with Rider D had been in effect and charged during the period January 1, 2003 to May 31, 2003.

D. Other Matters: Stakeholders' Right to Audit

27. The Parties agree that any party to the Settlement, other than the ISO, may elect on 30 days written notice, to select an audit firm, subject to paragraph. 29, below, to perform an audit in respect of the ISO's compliance with the specific terms of this Settlement for the year, as long as notice is received by the TA within 120 days after the 2003 ISO Annual Report and financial results have been issued by the ISO.

28. An audit undertaken pursuant to paragraph. 27, above, shall be performed at the expense of the Party or Parties which have elected to have the audit performed, unless the audit assists and is approved by the Board .

29. Any audit undertaken pursuant to paragraph. 27, above, shall be performed by a national audit firm which does not represent the Stakeholders, the ISO or other electric utility company.

30. The ISO shall retain all financial records pertaining to 2003 revenue requirement and 2003 financial results. The ISO shall provide all reasonable cooperation, including access to source data necessary or desirable for the effective and efficient completion of the audit.

31. The Party or Parties which elect to have an audit undertaken pursuant to paragraph. 27, above, will ensure that an audit report is prepared by the person or persons who complete the audit, and that a copy of the audit report is provided to the ISO in a timely fashion. Any Party may provide a copy of the audit report to the Board.

32. The terms of reference of the audit will be determined by the Party requesting the audit, with input from the ISO, both Parties acting reasonably. The audit will generally be in the form of a special purpose report pursuant to the CICA Handbook.

E. Other Matters: Financial

33. The ISO is committed to maintain a high quality of service, including the need to provide complete and timely responses to Board directives, and will ensure that cost savings will not be obtained at the expense of system reliability, safety or customer satisfaction. The ISO will exercise prudent business practices.

34. The ISO agrees:

(a) not, without prior approval from the Board, to implement any further material changes to its Terms and Conditions of Service;

(b) not, without prior approval from the Board, to make any material changes in accounting policy or practice from those approved by the Board for 2003. The ISO will provide descriptions of any change to its accounting policies and practices that impacts its revenue requirement to confirm the non-materiality of such changes, both individually and cumulative, on its 2003 revenue requirement; and

(c) that the business practices regarding ratchet waiver notifications, as outlined in Transmission Administrator Operating Policy OP-226, dated May 14, 2003 will continue to be applied until such time as the Board issues a decision in respect of the ISO's 2004 GTA.

F. Miscellaneous

35. Representations of the ISO:

(a) This Settlement and material filed by the ISO in its 2003 GTA, including all information responses provided to Parties by the ISO and filed with the Board in respect of the 2003 GTA, contain all material information and facts relied upon by the ISO to support its 2003 GTA (more specifically, the Phase I and Phase II appendices);

(b) To the knowledge of the ISO, the information provided by it in all of its submissions and meetings with the Stakeholders during the negotiations do not contain any untrue statement of material fact. The ISO acknowledges that the Stakeholders have relied upon, amongst other things, such information in agreeing to this Settlement;

(c) To the knowledge of the ISO, the information provided by it, in all of its written information and submissions and meetings with Stakeholders during the negotiations, does not omit any statement of material fact necessary to make the information provided accurate and true;

(d) At this time and except as noted herein, the ISO has no plans or intentions that would materially affect the 2003 GTA (more specifically, the Phase I and Phase II appendices);

(e) The ISO agrees that a breach of any of the covenants set out in this section would constitute a substantial and unforeseen change in circumstances for purposes of s. 126(2) of the *EUA* and, in any event, provide sufficient grounds for the Board to review the Order approving the Tariffs contemplated in the Settlement to determine if the continuation of such Tariffs is just and reasonable; and

(f) For the purposes of this section and the Settlement more generally, where the context permits, "material" means a fact or a change that significantly affects, or would reasonably be expected to have a significant effect on, the Settlement or, more particularly, on the ISO's revenue requirement.

36. This Settlement constitutes the entire agreement among the Parties and no other agreements, expressed or implied, have been made.

37. The ISO submits that the Settlement, as proposed herein, is fair, reasonable and in the public interest, and the Stakeholders agree to support the Settlement and an application to the Board in order to give effect to the terms of the Settlement.

38. In the event Stakeholders seek the recovery of costs from the Board for participation in this negotiated settlement, the ISO shall not make objections provided such claims are reasonable.

39. Appended hereto are executed signature pages of the Parties (which may be executed in counterparts) which indicates their concurrence with the Settlement as reflected in this agreement.

IN WITNESS WHEREOF the Parties have executed this Agreement effective as of the _____ day of June, 2003 at Calgary, Alberta.

Independent System Operator a corporation carrying on business as Alberta Electric System Operator	ATCO Electric Ltd.
By: _____	By: _____
Name: David Erickson	Name: W. James Beckett

Title: Chief Financial Officer

Title: Executive Vice-President, Regulatory

AAMD&C (Alberta Association Municipal Districts & Countries)

By: _____

Name: Gerald Rhodes

Title: Executive Director

AFREA (Alberta Federation REA's Ltd.)

By: _____

Name:

Title:

AltaGas Services Inc.

By: _____

Name: Dennis Dawson

Title: Vice President, General Counsel and Corporate Secretary

AltaLink Management Ltd.

By: _____

Name: Mr. Bob Schmidt

Title: Senior Vice-President Regulatory

ATCO Power Canada Ltd.

By: _____

Name: Grant Lake

Title: Vice-President, Commercial

AUMA (Alberta Urban Municipalities Assoc.)

By: _____

Name: George Rogers

Title: President

City of Medicine Hat

By: _____

Name: Doug Crichton

Title:

COS Coalition

By: _____

Name: Dale Hildebrand Consultants

Title:

EnCana Corporation

By: _____

Name:

Title:

ENMAX Corporation

By: _____

Name: Scott Stoness

Title: Vice-President, Regulatory Affairs

EPCOR Utilities Inc.

By: _____

Name: Bryan DeNeve

Title: Vice-President, Regulatory Affairs

City of Calgary

By: _____

Name: Norm Carruthers

Title: General Manager

IPPSA

By: _____

Name:

Title:

City of Red Deer

By: _____

Name:

Title:

TransCanada Energy Ltd.

By: _____

Name:

Title: Vice-President, Western Power

TransAlta Utilities Corporation

By: _____

Name: Ms. Sandy O'Connor

Title: Director, Commercial Management

City of Lethbridge

By: _____
Name:
Title:

IPPCCA

By: _____
Name: Dan MacNamara
Title: Executive Director

Public Institutional Consumers of Alberta

By: _____
Name: Nancy McKenzie
Title:

Alberta Irrigation Projects Association

By: _____
Name: David Hill
Title: Executive Director

Consumers Coalition of Alberta

By: _____
Name: James Wachowich
Title:

Alberta Direct Connect Consumer Association

By: _____

Name: Darwin Gillies

Title: Executive Director

APPENDIX 1

ALBERTA ELECTRIC SYSTEM OPERATOR

2003 TARIFF

TERMS AND CONDITIONS OF SERVICE

TABLE OF CONTENTS

ARTICLE NO.	DESCRIPTION	PAGE NO.
Article 1	Definitions And Interpretation	3
Article 2	Application Of Tariff	12
Article 3	Use Of Transmission System	13
Article 4	System Support Services	15
Article 5	Interconnection Requirements	16
Article 6	Opportunity Service	18
Article 7	Application Fee	20
Article 8	Security For New Transmission Facilities	23
Article 9	Customer Contribution Policy	24
Article 10	Credit, Statement Of Account And Payment Terms	29
Article 11	Provision Of Information By Customers	31
Article 12	Metering	34
Article 13	Service Interruptions And Force Majeure	36
Article 14	Limitation Of Liability	37
Article 15	Increases, Reductions Or Terminations Of Contract Capacity	38
Article 16	Dispute Resolution	40
Article 17	Maintenance Of Records	41
Article 18	Costs Associated With Rebilling	42
Article 19	Notifications	43
Article 20	SPRDA Generators	44
Article 21	Peak Metered Demand	45
Article 22	Transmission System Expansion	46
Article 23	Miscellaneous	47
Article 24	Emergency Provision Of System Support Services	48
Article 25	Confidentiality	50
	APPENDICES	
Appendix A	Intentionally Left Blank	52
Appendix B	System Access Service Agreement Proformas	53
Appendix C	Form of Construction Commitment Agreement	67
Appendix D	Metering Equipment Information	70
Appendix E	Regulated Generating Units	74

ARTICLE 1
DEFINITIONS AND INTERPRETATION

1.1 Unless otherwise expressly provided, any definition of a word or expression in the Act shall apply to the use of such word or expression in this Tariff. Notwithstanding the foregoing, the following terms shall have the following meanings in this Tariff:

"Act" means the *Electric Utilities Act*, S.A. 2003, c. E-5.1, as amended.

"AESO" means Alberta Electric System Operator, and is a trade name under which the ISO carries on business in fulfillment of its roles, responsibilities and duties pursuant to the Act.

"AIES" means Alberta's "Interconnected Electric System" as that term is defined in the Act.

"AEUB" means the Alberta Energy and Utilities Board.

"Affiliate" has the meaning ascribed to it in the *Business Corporations Act* (Alberta), S.A. 1981, c. B-15, as amended.

"Apparent Power" means the product of the volts and amperes, comprising both real and reactive power, usually expressed in kilovoltamperes ("kVA") or megavoltamperes ("MVA").

"Application Fee" means the non-refundable interconnection application fee a Customer pays to the AESO when the Customer submits a request for interconnection to the AIES. Application Fees are set out in Article 7.

"Area Control Error" means the instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias (and time error or unilateral inadvertent energy, if automatic correction for either is part of the AGC);

"Automatic Generation Control" or **"AGC"** means equipment that automatically adjusts a Control Area's generation to maintain its frequency or interchange schedule plus or minus frequency bias.

"Automatic Voltage Regulator" or **"AVR"** means automatic control equipment that changes the Generating Unit excitation level to maintain voltage levels.

"Billing Capacity" shall have the meaning given to that term in Rate Schedule DTS.

"Billing Period" means a period of time starting on the first day of each calendar month at 00:00 hrs. and ending on the last day of the same calendar month at 24:00 hrs., during which a Customer is supplied with System Access Service by the AESO.

"Business Day" means a day other than a Saturday, a Sunday, a Statutory Holiday, or a Monday when a Statutory Holiday occurs on a Saturday or Sunday and the following Monday is a day during which financial banking privileges are suspended.

"Commercial Operation" means the date upon which a load or Generating Unit begins to operate on the transmission system in a manner which is acceptable to the AESO and which is expected to be normal for it to so operate, after energization and Commissioning.

"Commissioning" means those limited activities (as approved in advance by the AESO and subject to written agreement) conducted after interconnection which are required to ensure that a facility can satisfactorily enter Commercial Operation and that a facility meets the AESO's requirements. Such written agreement will not extend beyond a three month period or a mutually agreed to commissioning period.

"Confidential Information" means information provided to the AESO which has been specifically identified as being confidential in nature by the provider of such information and information provided pursuant to Article 11 of these T&C's.

"Confirmation Notice" is a notification from the AESO to a customer that the Customer's system access service application is complete and will be processed.

"Constrained On" means, in respect of a Generating Unit, being dispatched on load while Out of Merit, as a result of a Dispatch Instruction by the System Controller.

"Construction Commitment Agreement" means an agreement to be entered into between the AESO and a Customer prior to the AESO arranging for new facilities required to accommodate System Access Service or an increase thereto, as referenced in Paragraph 8.1 hereof.

"Contract Capacity" means the peak demand or supply capability (expressed in MW), as set out in the System Access Service Agreement; it may change only in accordance with the provisions of the terms hereof.

"Control Area" means a geographic area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control

areas, and contributing to frequency regulation of the interconnection, such as the AIES.

"COS" or **"Customer-Owned Substation Credit"** means the credit payable to certain Demand Customers as set forth in Rate Schedule Customer-Owned Substation Credit.

"Customer" is an Eligible Person who takes, or applies to take, System Access Service from the AESO and satisfies the pre-contract conditions provided in Paragraph 3.1 below.

"Customer's Facilities" means all facilities interconnecting with the AIES on the Customer's side of the POD or POS.

"Customer Contribution" means the amount required to be paid by Customers taking service under Rate Schedule DTS or Rate Schedule STS pursuant to Article 9 hereof.

"Deficiency Notice" is a notification from the AESO Customer that the Customer's system access service application is deficient and the application will not be processed.

"Demand Customers" are load customers and generation customers, the latter for the purposes of obtaining their back up supply.

"Direct Loss or Damage does not include loss of profit, loss of revenue, loss of production, loss of earnings, loss of contract or any other indirect, special or consequential loss or damage whatsoever arising out of or in any way connected with a AESO Person Act.

"Dispatch Instruction" means in respect of any Generating Unit, all dispatch instructions issued by the System Controller from time to time, designating such unit to provide System Support Services, by changing the output or manner of operation of a unit, or by another method or procedure, and giving any necessary details as to the service to be provided.

"Dispute" means any dispute, claim or difference which arises in respect of the Tariff between the AESO and the Customer.

"Distributor" means a party providing "distribution access service" as defined in the Act.

"DOS" or **"Demand Opportunity Service"** means service under any one of Rate Schedules Demand Opportunity Service (DOS 7 Minutes), Demand Opportunity Service (DOS 1 Hour), Demand Opportunity Service (DOS Term).

"DTS" or **"Demand Transmission Service"** means service under Rate Schedule Demand Transmission Service.

"E&GI Act" means the *Electricity and Gas Inspection Act* (Canada) and regulations made thereunder, as amended from time to time, or such replacement legislation as may be enacted.

"Eligible Person" means any of the following: the owner of a Generating Unit; the owner of an electric distribution system; an importer or exporter; the owner of an industrial system; a direct access customer or the purchaser of a PPA in accordance with Part 6 of the Act.

"Emergency" means, as declared by the System Controller, either: any abnormal system condition which requires immediate manual or automatic action to prevent abnormal system frequency deviation, abnormal voltage levels, equipment damage, or tripping of system elements which might result in cascading effects; or a state in which the AIES lacks sufficient System Support Services.

"Energy Transfer" shall mean the quantity of energy transfer attributable to a transaction for service under Rate Schedule Export Service or Rate Schedule Import Service, based on the capacity at a Point of Interconnection and allocated to a Customer.

"Export Service" means service under Rate Schedule Export Service.

"Force Majeure" means: acts of God; strikes; lockouts or other industrial disturbances; vandalism; wars; riots; epidemics; landslides; lightning; earthquakes; explosions; fires; storms; intervention of federal, provincial, or local government (or from any of their agencies or boards); the order or direction of any court; inability to obtain, interruption, suspension, curtailment or other diminution of, supply of materials, utilities, or services from any supplier (including, without limitation, TFOs, System Support Service Providers or the System Controller) and any other causes, whether of the kind herein enumerated or otherwise, not within the control of the AESO and which by the exercise of due diligence the AESO is unable to prevent or overcome.

"Generating Unit" shall have the meaning as ascribed to in the Act.

"Governor" or **"Governor System"** means automatic control equipment with speed droop characteristics to control Generating Unit speed and/or electric power output.

"Hourly Application Fee" means the actual AESO's costs associated with processing a Customer's request for interconnection to the AIES plus 30 per cent.

"Import Service" means service under Rate Schedule Import Service.

"Interconnection Requirements" means the requirements contained in the *Technical Requirements for Connecting to the Alberta Interconnected Transmission Grid* in either *Part 1: Technical Requirements for Connecting Loads or Part 2: Technical Requirements for Connecting Generators to the Alberta Interconnected Electric System*, published on the AESO's website, as may be amended from time to time in accordance with the provisions of Article 5 below.

"ISO" means the Independent System Operator, a corporation established under the Act and whose role, responsibilities and duties are more particularly described therein.

"Looped" refers to transmission facilities that increase the number of electrical paths between any two POCs other than the POC that serves the Customer for whom the facilities are being or have been constructed.

"Losses" means the energy that is lost through the process of transmitting electric energy.

"MCR" means Maximum Continuous Rating. MCR is the maximum net power output that can be sustained by a generator over a long period.

"Metered Demand" means the rate at which electric energy is delivered to a POD, or from a POS, expressed in kW or MW, averaged over a 15-minute, 1-minute or other interval as deemed necessary by the AESO.

"Metered Energy" means the quantity of energy reflected by the relevant Metering Equipment as having been transferred in a particular period of time.

"Metering Equipment" means any current transformers, potential transformers, interconnecting wiring, meters, remote metering communication facilities and records used by the owner of the Metering Equipment in connection with these Terms and Conditions to measure Metered Demand.

"Non-dispensated Metering Equipment" means Metering Equipment installed after May 31, 1998 which is not the subject of a waiver or dispensation by Industry Canada of requirements under the E&GI Act.

"Non-Recallable Customer" means a Customer taking System Access Service pursuant to Rate Schedule DTS or Rate Schedule STS.

"Off-Peak" means those periods of time which are not On-Peak.

"On-Peak" means the period of time from 8:00 hrs. to 21:00 hrs., inclusive, during any Business Day.

"Operating Reserves" means the capability above system demand available to the AIES within 10 minutes following a supply contingency, required to provide for system regulation and local area protection and to correct for or stabilize the system in the event of contingencies, load forecasting errors and forced outages to Generating Units. Operating Reserve includes any or all of the following in any combination at a given time:

(a) **"Regulating Reserve"**, being an amount of Spinning Reserve responsive to AGC, which is sufficient to provide normal regulating margin;

(b) **"Spinning Reserve"**, being the amount of reserve synchronized to the AIES, responding automatically through governor action to fluctuations in AIES frequency and capable of assuming load instantaneously;

(c) **"Non-spinning Reserve"**, being the amount of generation capable of being connected to the AIES and loaded within 10 minutes, or demand that can be reduced within 10 minutes;

(d) **"Contingency Reserve"**, being a combination of Spinning and Non-spinning Reserve and of sufficient quantity to reduce Area Control Error to zero within 10 minutes following the loss of supply capacity. At least 50% of the Contingency Reserve shall be Spinning Reserve, which will automatically respond to frequency deviation.

"Opportunity Capacity" means the incremental amount of transmission capacity which is available under a System Access Service Agreement for Demand Opportunity Service to provide capacity in addition to Contract Capacity for DTS.

"Opportunity Service" means System Access Service offered to any Customer who can establish to the AESO's satisfaction that it would not take System Access Service pursuant to Rate Schedule DTS and with respect to which, therefore, the service requirement presents the opportunity for incremental revenue with which the AESO can offset transmission costs.

"Opportunity Service Customers" means those Customers which meet the criteria for Opportunity Service, as defined.

"Physical Capacity" means the maximum amount of electric power which a transmission facility, as rated by a TFO, is able to transmit.

"POC" or **"Point of Connection"** means a point at which electric energy is transferred between the Customer's facility and the AIES. A Point of Connection may be a Point of Supply (POS), a Point of Delivery (POD), or both.

"POD" or **"Point of Delivery"** means the point at which electric energy is transferred from the AIES to a Customer's facilities.

"Point of Interconnection" means the point at which electrical energy is transferred from the AIES to a neighboring jurisdiction and where the electric energy so transferred is measured;

"Pool Price" shall have the meaning ascribed to that term in the Act, and when used in the context of a particular hour, shall mean the pool price for that hour;

"POS" or **"Point of Supply"** means the point which electric energy is transferred from a Customer's facilities to the AIES.

"Power Factor" means the ratio of Real Power to Apparent Power.

"PPA" or **"Power Purchase Arrangement"** means those instruments setting forth the rights and obligations of the parties in relation to operation of Regulated Generating Units and entitlements to electricity and System Support Services and approved by the AEUB under Part 6 of the Act.

"PPA Effective Date" means January 1, 2001 or such other date as the Power Purchase Arrangements become effective.

"PSS" means power system stabilizer.

"Radial" facilities are those transmission facilities that are not Looped.

"Ratchet Level" shall have the meaning ascribed thereto in Rate Schedule DTS.

"Rate Schedules" means the schedules attached to and forming part of the Tariff, which set out the respective rates to be charged, and credits to be attributed, for each type of System Access Service.

"Rated Capacity" means the maximum amount of electric power which a transmission facility is rated by the manufacturer to be able to transmit.

"Reactive Power" means the portion of electricity that establishes and sustains the electric and magnetic fields of alternating current equipment, usually expressed in kilovars ("kVAr") or megavars ("MVAr").

"Real Power" means the rate of producing, transferring, or using electrical energy, expressed in kilowatts ("kW") or megawatts ("MW").

"Regulated Generating Unit" shall have the meaning ascribed thereto in the Act;

"Representatives" means the directors, officers, employees, consultants and agents of the AESO.

"RMS" means the Reliability Management System (and all mandatory operating criteria required thereby) adopted and enforced by the WSCC.

"Statutory Holiday" means New Years Day, Family Day, Good Friday, Victoria Day, Canada Day, Heritage Day, Labour Day, Thanksgiving Day, Remembrance Day, Christmas Day and Boxing Day.

"STS" or **"Supply Transmission Service"** means service under Rate Schedule Supply Transmission Service.

"STS Capacity" means the Contract Capacity as set out in the System Access Service Agreement for Supply Transmission Service.

"System Access Service" or **"service"** has the meaning ascribed to the term "system access service" in the Act;

"System Access Service Agreement" means that contract, entered into between the ISO carrying on business as the AESO and a Customer, in one of the forms attached hereto as Appendix "B", which establishes the specific terms pursuant to which each individual Customer obtains System Access Service.

"System Controller" or **"SC"** shall have the meaning ascribed to that term in the Act.

"System Disturbance" means an unplanned event, which produces an abnormal AIES condition such as high or low frequency, abnormal voltage or oscillations in the AIES.

"System Security" means the ability of the AIES to withstand events such as electric short circuits, unanticipated loss of AIES components and switching operations without experiencing cascading loss of AIES components or uncontrolled loss of load.

"System Support Services" shall have the meaning ascribed to that term in the Act.

"Tariff" means these Terms and Conditions and Appendices attached hereto and the Rate Schedules as approved by the AEUB.

"TFO" means Transmission Facilities Owner.

"Transmission Administrator Operating Policies" or **"TAOPs"** means the standards and practices established by the AESO to guide operation of the transmission system, as modified by the AESO from time to time.

"Transmission Must-Run" means Constrained On dispatch of a Generating Unit to a specific level in accordance witn a Dispatch Instruction to maintain System Security.

"UFS" or **"Under-frequency Load Shedding Credit"** means the under-frequency load shedding provisions as set forth in Rate Schedule Demand Under-Frequency Load Shedding and the credits therefor.

"Western Interconnection" means the area comprising those states and provinces, or portions thereof, in Western Canada, Northern Mexico and the Western United States in which members of the WSCC operate synchronously connected transmission systems.

"WSCC" means the Western Systems Coordinating Council and any successor organization.

ARTICLE 2
APPLICATION OF TARIFF

2.1 This Tariff sets forth the basic terms and conditions of service pursuant to which the AESO will provide System Access Service to its Customers. This Tariff has been approved by the AEUB, defines service to be delivered by the AESO and binds all of the AESO's Customers. This Tariff defines the basic rights of the AESO and all its Customers with respect to all services provided by the AESO. By accepting service from the AESO, a Customer is deemed to have accepted the terms and conditions and Rate Schedules contained in this Tariff. This Tariff becomes effective on the later of January 1, 2003 or the first day of the month after the AEUB approves it.

This Tariff shall continue in effect until replaced or amended pursuant to Section 124 of the Act.

ARTICLE 3
USE OF TRANSMISSION SYSTEM

3.1 The AESO agrees to provide and make available System Access Service to all Customers who:

(a) satisfy the pre-contract conditions set out in Articles 5, 6 (and the definition of Opportunity Service Customers), 7, 10, 11, 12, and 21 and the applicable Rate Schedule(s);

(b) have executed a System Access Service Agreement; and

(c) continuously abide by these terms and conditions.

3.2 The AESO reserves the right to withhold, limit or discontinue System Access Service under the following provisions:

(a) Article 4, System Support Services

(b) Article 5, Interconnection Requirements

(c) Article 10, Credit, Statement of Account and Payment Terms;

(d) Article 11, Provision of Information By Customers;

(e) Article 12, Metering;

(f) Article 13, Service Interruptions and Force Majeure;

(g) Article 15, Increases, Reductions or Termination of Contract Capacity; and

(h) the Rate Schedules, where appropriate.

In the event of a written request from a Customer, the AESO shall provide a written explanation for its withholding System Access Service.

3.3 All Customers shall comply with the Interconnection Requirements. Failure to comply with Interconnection Requirements shall provide the AESO with the right, at its sole discretion, to withhold or discontinue System Access Service.

3.4 The AESO provides System Access Service to Customers up to and including the POD or POS. All facilities interconnecting with the AIES on the Customer's side of the POD or POS ("Customer Facilities") are the responsibility of the Customer. This Tariff applies only to System Access Service supplied through facilities up to or from, and including, the POD or POS. The Customer must supply all Customer Facilities and the AESO has no responsibility in respect of service provided over Customer Facilities.

3.5 No Customer or any other person may rearrange, disconnect, remove, interconnect with, or otherwise interfere with any transmission facility without the AESO's prior written consent.

ARTICLE 4

UNDER-FREQUENCY LOAD SHEDDING

4.1 From and after the effective date of the Tariff, certain Customers may be eligible and required to provide under-frequency load shedding. The provisions with respect to those requirements, and the credits therefore, are set out in Rate Schedule Under-Frequency Load Shedding ("UFS").

4.2 Failure by any Customer to whom UFS applies to comply with the requirements thereof may cause the AESO to, at its sole discretion, withhold, limit or discontinue System Access Service to such Customer. Nothing in this paragraph shall, however, affect or derogate from the right of the WSCC to levy penalties or the obligation of the Customer, if any, to pay such penalties as a result of failure to provide Under-Frequency Load Shedding to the AESO as contemplated herein.

ARTICLE 5
INTERCONNECTION REQUIREMENTS

5.1 Any Customer proposing to take, or is taking, System Access Service through a POD or POS must comply with the Interconnection Requirements.

5.2 Any Customer whose facilities include a synchronous Generating Unit which is operated in parallel to the electric system, whether connected at a transmission voltage or a distribution voltage, must have a PSS in service when the Generating Unit is operating and an AVR that is operated in a voltage control mode for all hours in which the Generating Unit is operating. The Customer shall not operate the Generating Unit unless the PSS and AVR are operating as required. The Customer shall report to the AESO on a monthly basis, no later than the 5th Business Day of the month following the month to which the report relates, the PSS and AVR in-service periods for the preceding month. In the event that the AESO becomes aware of a failure to comply with this requirement, the AESO shall report the non-compliance to the WSCC and any penalties assessed by the WSCC as the result of the noncompliance shall be borne by the relevant Customer. Article 5.2 shall not apply to synchronous Generating Units 10 MVA and smaller that are connected at the distribution voltage until such time that the aggregate MVA output from such 10 MVA and smaller synchronous Generating Units connected at a distribution voltage in the Alberta Control Area exceeds 200 MVA.

5.3 Failure to comply with the Interconnection Requirements shall result in the AESO withholding, suspending or terminating System Access Service, however the AESO may, in its sole discretion, waive compliance with the Interconnection Requirements or the requirements of Paragraph 5.2 in respect of any existing Customer for whom, in the AESO's reasonable opinion, the imposition thereof would create severe hardship or unnecessary costs.

5.4 The AESO shall maintain the reliability of the AIES and the Western Interconnection in accordance with the RMS. The AESO may amend the Interconnection Requirements in order to reflect, and to adhere to, changes to the RMS from time to time, upon further approval by the AEUB.

5.5 Article 5.2 does not apply to generators in existence as of June 1, 2000 that do not have a suitable excitation system unless the AESO indicates otherwise. If the AESO requires PSS or AVR to be added to a currently regulated generator in the future, the AESO will pay any costs prudently incurred in the installation of the PSS or AVR and will recover prudently incurred costs from tariff(s) approved by the AEUB. Any costs incurred by the currently regulated generators in the installation of the PSS or AVR that are found by the AEUB to be imprudent in any AESO tariff proceeding will be reimbursed to the AESO by the party receiving the payment.

5.6 If the excitation system of an existing regulated or unregulated generator to which Article 5.2 does not apply is rebuilt or replaced, the new excitation system must be suitable for PSS, and a PSS/AVR must be installed.

ARTICLE 6
OPPORTUNITY SERVICE

6.1 To qualify for Opportunity Service the Customer shall submit a pre-qualification application to the AESO. The Customer must also meet the specified eligibility criteria and must demonstrate that the intended use of the service would not proceed any other applicable rate. The Customer will pay a non-refundable $5,000 fee to the AESO to evaluate the commercial eligibility of the Customer's DOS pre-qualification application. See Appendix B for a copy of the appropriate DOS proformas.

6.2 An Opportunity Service Customer shall only consume Opportunity Service for Metered Energy above its Contract Capacity. Opportunity Service Customers shall take System Access Service for all Billing Capacity equal to or below the Contract Capacity pursuant to Rate Schedule DTS.

6.3 In the event that the Metered Energy in a Billing Period for an Opportunity Service Customer is taken at a rate above the aggregate of the Opportunity Capacities under all such Customer's Opportunity Service System Access Service Agreements:

(a) The Metered Energy transfer at a rate above the said aggregate of Opportunity Capacities shall be added to the Metered Energy for the purpose of calculating the Customer's charges for that Billing Period under Rate Schedule DTS; and

(b) In the event that an Opportunity Service Customer has a Contract Capacity of zero and has not executed a System Access Agreement for DTS services, such Customer shall be deemed to have executed such an agreement, effective the beginning of the relevant Billing Period for which the aggregate of Opportunity Capacities was exceeded, for the purposes of determining a Billing Capacity, and for the purposes of applying the charges referred to in paragraph (a) above.

6.4 Opportunity Service is recallable:

(a) in accordance with the Rate Schedules;

(b) in accordance with the provisions of Article 13 below;

(c) whenever sufficient transmission system capacity becomes temporarily or permanently unavailable; and

6.5 From time to time, the AESO may audit any Customer's eligibility for Opportunity Service. If, as a result of its audit, the AESO finds that the Customer is or has been serving loads which do not, or no longer, qualify for Opportunity Service, the AESO will change the Rate Schedule pursuant to which the Customer is

billed. The AESO may, in its sole discretion, recover retroactive amounts equal to the payments the Customer would have had to make if it had been taking System Access Service as a Non-Recallable Customer for the periods during which such Customer did not qualify for Opportunity Service. In the event the AESO determines that the Customer is no longer qualified for Opportunity Service and prior to executing an agreement for Non Recallable Service, the Customer will be deemed to have executed such agreement, with the effective date of such agreement to be the effective date of disqualification.

6.6 Opportunity Service contracts will be offered under the following conditions:

(a) Commencement of the initial application for opportunity service must be requested at least 30 days prior to taking opportunity service;

(b) The applicant must have been determined, in the sole opinion of the AESO to have met the commercial eligibility criteria for Opportunity Service and in particular the use of the Opportunity Service would not proceed on any other applicable rate;

(c) subsequent applications for opportunity service with the same parameters as the initial qualification application must be requested at least one hour prior to taking opportunity service;

(d) the minimum term of an opportunity service shall be a continuous eight hours from 00:00 hrs. midnight to 24:00 hrs., or such other minimum term as the AESO may, in its discretion, set; and

(e) the maximum term of an opportunity service is one calendar month.

ARTICLE 7
INTERCONNECTION APPLICATION FEES

7.1 Effective January 1, 2002, the AESO shall charge and the Customer shall pay a non-refundable interconnection application fee (the "Application Fee") to recover the AESO's internal costs associated with a Customer's request for interconnection to the AIES. These costs may include, but are not limited to, the costs of estimating, engineering, customer service, project management, contracting and administration. The AESO will not process the Customer's application, conduct the analysis or provide the detailed information to the Customer until the Customer has provided the AESO with:

(a) a completed system access application form (copies of the Stage 1 and Stage 2 application forms can be obtained from the AESO's website); and

(b) subject to Paragraph 7.4, the Application Fee paid in full.

7.2 Subject to Paragraph 7.4, the Application Fee charged is broken down into two stages and the stages are further broken down depending on the size of the Customer's proposed project:

(a) Stage 1 fees cover the AESO's costs to provide the Customer:

(i) a draft functional specification;

(ii) in the case of a Customer which is a generator, a preliminary loss factor calculation; and

(iii) a cost estimate of the work specified in the draft functional specification;

(b) Stage 2 fees cover the AESO's costs to provide the Customer:

i) an energization certificate.

ii) application by the TFO for transmission facilities;

iii) supporting letter from the AESO to the Board on the facility application by the TFO; and

iv) provision of a System Access Agreement.

7.3 The Stage 1 and Stage 2 Application Fees are as follows:

Project Size	Stage 1 Fee	Stage 2 Fee
< 10 MW	$5,000	$5,000
> 10MW≤ 15 MW	$8,000	$8,000
> 15 MW ≤ 25 MW	$15,000	$15,000
> 25 MW	$40,000	$50,000

7.4 At the start of Stage 1 or Stage 2 the Customer, at its sole discretion, may elect to pay the actual AESO costs associated with interconnection plus thirty percent (the "Hourly Application Fee") instead of the Stage 1 or Stage 2 Application Fees.

If the Customer elects to pay the Hourly Application Fee, the Customer will provide the AESO with a deposit equal to the applicable Stage 1 or Stage 2 Application Fee. At the completion of the stage of the project the AESO will provide the Customer with a detailed invoice of the work. If the deposit exceeds the amount of the invoice, the AESO will refund the excess funds to the Customer. If the amount of the invoice exceeds the deposit the Customer shall pay the AESO the amount owing.

7.5 Within five (5) business days of receiving a system access service application form and full payment of the Application Fee, the AESO will review the system access service application to determine if it is complete and contains all the necessary information.

7.6 If the system access service application is complete the AESO will notify the Customer, in writing, that the system access service application is complete (the "Confirmation Notice").

7.7 If the system access service application is not complete or the Application Fee has not been paid in full, the AESO will notify the Customer, in writing, of the deficiencies (the "Deficiency Notice") and the application will not be processed.

7.8 A Customer or potential Customer may request the AESO provide a preliminary loss factor calculation (only), in which case the Customer shall provide a completed loss factor calculation application form (copies of which can be obtained from the AESO's web site) and pay a non-refundable fee of Twenty five hundred dollars ($2,500) to the AESO.

7.9 For all other requests for service the Customer shall pay the AESO's actual costs to prepare and provide the information, pursuant to the procedure set out in Paragraph 7.4.

7.10 Upon the AESO providing the Customer with the documents and information set out in paragraph 7.2(a) at the completion of Stage 1, the Customer has sixty (60) days to notify the AESO whether the Customer is proceeding to Stage 2, and , in

the event it is proceeding, provide the AESO with a completed Stage 2 application form. If the Customer elects not to proceed, does not notify or provide the AESO with the Stage 2 application (along with Stage 2 Application Fee) within the 60 day period, the Customer's system access service application will be deemed to have been cancelled and the project shall be removed from the AESOs' project list.

7.11 If a Customer's system access service application has been cancelled pursuant to paragraph 7.10, and the Customer subsequently wishes to reinstate its application the Customer must start the application process from the very beginning (i.e. submit a Stage 1 application and Application Fees pursuant to paragraph 7.1).

7.12 All detailed studies shall be conducted by the AESO in the order in which the AESO receives payment therefor. In the interest of maintaining confidentiality of each and every Customer and potential Customer, the AESO shall conduct all detailed studies only on the basis of available information about actual and planned AIES facilities. For planning purposes, only those facilities with respect to which a Construction Commitment Agreement has already been executed shall be deemed "planned facilities". The AESO shall not be liable to any Customer or potential Customer for any changes to the actual or planned facilities which occur between the date upon which the AESO issues the detailed study and the date upon which the Customer executes a Construction Commitment Agreement.

7.13 All applications made by customers under previous Tariffs will continue to be offered service in accordance with those Tariffs. Stage 1 and Stage 2 fees will not be assessed to applications made prior to January 1, 2002. Any application made prior to January 1, 2002, which does not reach the end of Stage 1 by December 1, 2002, will be terminated.

ARTICLE 8
SECURITY FOR NEW TRANSMISSION FACILITIES

8.1 The AESO is not obliged to arrange for commencement of the construction of new facilities required to initially facilitate System Access Service, or to accommodate increased Contract Capacity or Opportunity Capacity, for any Customer until that Customer has executed a Construction Commitment Agreement and, if required by the AESO, has provided to the AESO a performance bond, parental guarantee, irrevocable letter of credit or other security ("the security") in an amount adequate to fund cancellation costs as referenced in Paragraph 8.2 or the AESO's reasonable estimate thereof, (or any portion thereof deemed appropriate), up to, in the aggregate, a maximum of the estimated costs of construction. The security shall be satisfactory to the AESO in form and substance and the Construction Commitment Agreement shall be substantially in the form of the agreement attached hereto as Appendix "C".

8.2 In the event that, after a Construction Commitment Agreement is executed, the System Access Service and new transmission facilities are no longer required for any reason, the Customer shall pay all costs incurred in the procurement and construction of facilities to the date at which construction is ceased, plus all cancellation costs, penalties or other claims accrued due to the cessation and costs required for material salvage and reclamation of the construction site.

8.3 The Customer for whom new transmission facilities were built must execute a System Access Service Agreement prior to Commissioning of the new facilities. System Access Service shall be provided on a temporary basis for Commissioning at the Rate Schedule named in the System Access Service Agreement, however, during Commissioning (only), the Metered Demand may, at the sole discretion of the AESO, be disregarded in calculating the Ratchet Level for service under Rate Schedule DTS.

ARTICLE 9
CUSTOMER CONTRIBUTION POLICY

9.1 In considering requests to provide service to a new POC, or to increase the capacity of, or improve the service to an existing POC, the AESO will determine the appropriate means of delivering the requested service.

(a) If the AESO determines that the most economic option for providing service to a Customer is a facility other than a transmission facility (such as a distribution-level extension or isolated generation), or that the Customer's request primarily represents a shift of supply or demand from an existing POC, then the full cost of the transmission upgrade or extension ("the project") shall be borne by the Customer.

(b) Otherwise, the Customer's contribution to project costs shall be determined in accordance with Article 9.2 through 9.4.

9.2 Project costs will be classified as either system-related costs or Customer-related costs, as follows:

(a) The costs of that part of the project associated with Looped transmission extensions shall be classified as system-related costs, and shall be paid by the AESO.

(b) The costs of that part of the project associated with Radial transmission extensions shall be classified as system-related if it is proposed in the transmission development plan (as that plan exists on the date the project is Commissioned) that the extension become Looped within five years. The Customer shall pay the cost of advancing that part of the project from the date established in the transmission development plan, which cost shall be calculated as the difference between the present values of the capital costs of the advanced and as-planned projects using the discount rate as determined under Article 9.12.

(c) Where economics or system planning dictate that a facility larger than that required to serve the Customer is to be installed initially, then the cost of that portion of the project deemed to be in excess of the Customer's needs shall be classified as system-related. As the need to serve additional POCs arises, these system-related costs may be reclassified as Customer-related costs and allocated to the new Customers. The capacity between the Customer's requirements and the minimum size of facilities required to serve the Customer is not considered to be in excess of the Customer's requirements.

(d) All costs not identified under (a), (b), or (c) shall be classified as Customer-related costs. If the project is to serve a Customer not taking

service under Rate DTS, then the Customer shall pay all Customer-related costs. Otherwise, the Customer's contribution to Customer-related costs shall be determined in accordance with Articles 9.3 and 9.4.

9.3 Customer-related costs will be classified as either supply-related costs or demand-related costs, as follows:

(a) The fraction of Customer-related costs classified as supply-related shall be STS/(STS+DTS), where STS and DTS are the STS and DTS Capacities, respectively, at the POC. All supply-related costs shall be paid by the Customer.

(b) The Customer-related costs not classified as supply-related costs shall be classified as demand-related costs. The Customer's contribution to demand-related costs shall be in accordance with Article 9.4.

9.4 The Customer's contribution to the demand-related costs shall be calculated as follows:

(a) *Customer contribution = demand-related costs – roll-in ceiling*, where:

(i) *roll-in ceiling = commitment term amount + revenue-related amount*;

(ii) *commitment term amount* = $400,000 for every one-year commitment term after the first five-year commitment term. A commitment term is a period within which the Customer commits to maintain its Contract Capacity at or above its initial Contract Capacity. The maximum commitment term amount is $6 million.

(iii) *revenue-related amount* = three times the levelized annual revenue from the new or expanded service, where the levelized revenue is determined based on the projected Contract Capacities that are contracted at the time of the calculation of the Customer contribution. The discount rate to be used in the calculation of the levelized annual revenue shall be that established under Article 9.12.

(b) If the calculation in (a) results in a negative Customer contribution, no Customer contribution is payable. The AESO will make no payment to the Customer with respect to any excess of the roll-in ceiling over the demand-related costs.

9.5 Any Customer contribution to be paid to the AESO must be paid prior to the AESO initiating procurement of the required facilities, unless other credit

arrangements acceptable to the AESO are made. The discount rate to be used in any credit arrangement shall be that established under Article 9.12.

9.6 The cost estimate used in the calculation of project costs will be based on certain assumptions, including but not limited to assumptions about the method of construction, the routing of facilities, and the approvals and rights of way required to serve the Customer in accordance with the Customer's requests. In the sole opinion of the AESO, where a request for service is changed by a Customer or any assumptions are changed for reasons beyond the reasonable control of the AESO or the TFO, and a variance in the cost of the required facilities over the original estimate results, then:

(a) Subject to (b), where there is an increase in the Customer contribution, this amount is immediately payable to the AESO, or

(b) If feasible, the Customer and the AESO may modify the terms of the contract to adjust the Contract Capacity or the number of commitment terms.

(c) The Customer shall have the right to cancel the request for service by paying to the AESO, and/or the TFO, all costs then incurred or required to be incurred to discharge the AESO, and/or the TFO, of all obligations and to satisfactorily cancel the request for System Access Service.

9.7 Certain material events may result in a recalculation of the Customer contribution in respect of a project. Any recalculation shall make use of revised commitment terms, revenue-related amounts, and other available information, and may result in payments by the AESO to the Customer or by the Customer to the AESO. The circumstances giving rise to contribution adjustments include, but are not limited to, those in which:

(a) A Customer materially increases or decreases its Contract Capacity or number of commitment terms prior to the expiration of its original commitment terms;

(b) The actual Contract Capacities and/or incremental revenues turn out to be materially different, on a sustained basis, than originally projected;

(c) A facility that had been classified as system-related under Article 9.2(c) is reclassified as Customer-related due to load growth or the addition of a new POC.

(d) A material error is detected in the original calculation.

(e) A difference between the estimated costs of the project and the actual costs of the project.

9.8 If the AESO installs facilities to serve a Customer that is required to pay a contribution, and then uses those facilities to serve other Customers within 20 years of their Commissioning, the AESO will adjust the original Customer's contribution and assess each of the new Customers a contribution, as follows:

(a) The contributions of the existing Customer and the new Customers will be determined on the basis of:

(i) the commitment terms of the original and new Customers;

(ii) the revenue-related amounts of the original and new Customers;

(iii) the Contract Capacities of the original and new Customers;

(iv) the extent of shared facilities; and

(v) the time interval between the Commissioning of the original and new Customers.

(b) If the interval described in (a)(v) is not greater than five years, then the original Customer is eligible for the full amount of the adjustment. If the interval is greater than five years, then for the remaining 15 years the adjustment will be determined on a straight-line, declining-balance basis.

(c) Commencing in year 11, any project whose remaining adjustment is less than $50,000 shall be deemed to have an adjustment balance of zero, and no further refunds shall be due.

(d) An adjustment as described above will also apply to situations in which the AESO subsequently deems that all or part of an original Customer's facilities have become system-related.

9.9 Where relocation of transmission facilities is required, the AESO will ensure that all reasonable costs in relocating any transmission facilities are paid for by the Customer.

9.10 Where new facilities between adjacent Control Areas are required, the cost of such facilities will be shared equally between the AESO and the party responsible for costs in the other Control Area.

9.11 The AESO reserves the right to exercise its discretion, acting reasonably, in the application of the contribution policy. Without limiting the generality of this discretion, the AESO may:

(a) Limit the maximum number of commitment terms used to determine the roll-in ceiling.

(b) Determine costs to be system-related in certain circumstances that might, under strict application of the foregoing, have been classified as customer-related.

(c) Determine that a refund of a Customer contribution may not be given or that a refund may be deferred pending the attainment of certain specified conditions. Upon attainment of the specified conditions, the Customer may be eligible for a full or partial refund.

(d) Determine that a refund of a Customer contribution must be returned to the AESO where it is demonstrated that an error was made or that an inappropriate refund was given.

9.12 The discount rate applicable to payments due under this Article shall be determined as follows:

(a) For unassigned transmission facilities, for transmission facilities supplied to the AESO by an investor owned Transmission Facility Owner or for facilities supplied to the AESO by an income tax paying municipally owned Transmission facility Owner:

$$.65(GCB + 1\%) + .35(GCB + 3.5\%)/(1 - T)$$

where GCB is equal to the yield on 30-year Government of Canada bonds and T is equal to combined federal and provincial income tax rate for investor owned TFOs.

(b) For transmission facilities supplied to the AESO by a non income tax paying municipally owned Transmission Facility Owners:

the yield on 30-year Government of Canada bonds plus 1.9 percent.

ARTICLE 10
CREDIT, STATEMENT OF ACCOUNT AND PAYMENT TERMS

10.1 After Commissioning, the AESO will issue a Statement of Account for System Access Service to each Customer no later than fifteen (15) Business Days after the end of each Billing Period. The AESO will determine the payment required and funds owed by each Customer for System Access Service at each POD and POS, as applicable, using available Metered Demand, Metered Energy or Energy Transfer data, as applicable, to calculate charges and any applicable credits. The AESO may deduct amounts owing by the AESO to the Customer or its Affiliates under other agreements between the AESO and the Customer or its Affiliates from the Statement of Accounts.

10.2 All Customers requiring access to the AIES must execute a System Access Service Agreement with the AESO for each POD and POS.

10.3 A Customer obtaining System Access Service may be afforded credit by the AESO. The Customer shall provide the AESO with any financial information that the AESO reasonably requests prior to the AESO granting service in order that the AESO may establish the Customer's ability to pay and/or creditworthiness.

10.4 The AESO may request, at any time a deposit of up to three months' payment in advance for System Access Service, based on the AESO's estimate of the appropriate sum based on the Customer's historic usage.

10.5 If the Customer fails to provide adequate security or advance payment to the AESO within ten (10) days of the AESO's request, the AESO may immediately withhold or suspend the Customer's System Access Service. However any such withholding or suspension shall not relieve the Customer from any obligation to pay any rate, charge or other amount payable which has accrued or is accruing to the AESO.

10.6 The AESO may use estimated values to produce a Statement of Account when Metered Demand data is not available or is incomplete, when Metering Equipment fails, or when the data is under Dispute. The AESO may also use estimated values to produce a Statement of Account if the AESO's billing and settlement system is unable to produce a Statement of Account. In the event that a Statement of Account is based on estimated values, an adjustment will be made on a subsequent Statement of Account to reflect the use of actual or more appropriate estimated values and the AESO may increase or reduce the amount billed in a subsequent Statement of Account in order to correct any underpayment or overpayment.

10.7 Effective January 1, 2002, where a Customer is an industrial site where multiple POCs are required, the AESO may totalize the POCs and produce one Statement of Account for the Customer. The AESO will base its decision to

totalize on a review of the economics of providing more than one POC, reclassification of the site as an AEUB designated industrial system, or the existence of a credible transmission bypass alternative.

10.8 The Customer shall pay the entire amount reflected as owing by it on the Statement of Account, notwithstanding any unresolved Dispute between the AESO and the Customer, no later than the twentieth Business Day after the end of the Billing Period. Payment shall be made by way of electronic funds transfer to the bank account specified by the AESO.

10.9 Late payments by the Customer shall be subject to a late payment charge of 1.5% per month for each month or part thereof for which such payment is late. The AESO will also assess the defaulting Customer for all administrative and collection costs relating to the recovery by the AESO of amounts owed. The AESO may suspend System Access Service and realize upon any security provided by the defaulting Customer if the Customer is in arrears by more than one month. System Access Service to the Customer shall not thereafter be re-instated until the Customer has paid all amounts owing to the AESO in full and has restored or secured its credit facility in a manner satisfactory to the AESO.

ARTICLE 11
PROVISION OF INFORMATION BY CUSTOMERS

11.1 Customers shall provide the following information necessary to enable the AESO to provide and maintain System Access Service that is safe, adequate and proper. When the required information has an impact on safety or system security, failure to provide the required information will result in suspension, termination or delay of System Access Service. System Access Service will not thereafter be reinstated, terminated or modified (as the case may be) until the necessary information is provided to the AESO. When the required information does not have an impact on safety or system security, failure to provide the required information will result in the AESO making application for approval of an information sharing arrangement pursuant to the Act and seeking to recover 100% of the actual costs of pursuit of its application from the Customer whose actions necessitated the application.

11.2 In addition to payment of the Application Fee (provided for in Article 7 above), information is required prior to providing a detailed cost quotation for new System Access Service. Detailed information is required to assess the impact of new demand or generation on the system, to determine whether new transmission facilities will be required in order to accommodate the new load or generation, and to produce functional specifications necessary to procure any new transmission facilities.

11.3 A Demand Customer shall provide a detailed request for System Access Service to accommodate a new or increased demand, which must include information regarding the retail customer's identity, the location, peak expected operating demand, desired in-service date and a forecast of future demand.

11.4 A Supply Customer who is requiring service for new generation or increase in capacity at an existing generation plant must submit a detailed request for System Access Service. The request must include information regarding the electrical characteristics of the generator so that the AESO can complete a detailed analysis of impact on the system and produce a detailed cost quotation.

11.5 The appropriate forms for making a detailed request for System Access Service are published on the AESO's website.

11.6 Additional technical information shall be required during construction and prior to energization of new interconnections or increases of capacity at existing PODs and/or Commissioning at POSs so that the AESO may ensure the ongoing security of the existing electrical system. Technical information is required prior to energization of load, as requested by the AESO, regarding the new transmission facilities including, but not limited to, transformer and line information. Technical information is required prior to Commissioning of new generation, as requested by the AESO, including, but not limited to, data

regarding the electrical characteristics of the generator and unit transformer. The appropriate forms for fulfilling pre-commissioning information requirements are published on the AESO's website.

11.7 Additional information may be required prior to Commissioning and Commercial Operation. Commissioning shall not occur until the Customer has received written approval thereof from the AESO.

11.8 The AESO requires forecast information and updated information from all Customers to plan, operate and optimize the AIES. On October 1st of each calendar year and whenever new information arises, all Customers shall provide the AESO with a copy of the Customer's operating procedures and a schedule of planned or maintenance outages for the two subsequent calendar years. On October 1st of each calendar year and whenever new information arises, all Customers shall provide the AESO with forecast information for the subsequent five (5) years, including:

(a) Forecast Maximum Contract Capacity by POD or POS by month,

(b) Location and size of any new POD and POS required,

(c) Name and location of existing POD and POS which may no longer be required.

The appropriate forms for provision of forecast and update information are published on the AESO's website.

11.9 The AESO requires detailed information regarding Metering Equipment information. The Customer shall provide the AESO with the Metering Equipment information outlined in Appendix "D".

11.10 The Customer shall provide to the AESO, upon request, any information that the AESO requires in order to discharge its duties and functions under the Act and for compliance with any external agency's reporting requirements.

11.11 The AESO is not responsible for any delay, interruption, damage or other problems caused by a delay in the provision of information required from a Customer under the provisions of this Article 11.

ARTICLE 12
METERING

12.1 The selection, use and calibration of Metering Equipment shall be accomplished in accordance with the E&GI Act, except where the AESO requires revenue meters to be accurate to within 0.5% for loads up to 10 MVA and 0.2% for loads above 10 MVA (the "System Accuracy Standard").

12.2 The Customer may arrange to have any Non-dispensated Metering Equipment tested and/or calibrated to the System Accuracy Standard. If the Customer requests a test and the meter is subsequently found to be accurate within the System Accuracy Standard, then the Customer shall pay for the cost of the testing and shall be invoiced for this cost in its next Statement of Accounts.

12.3 The AESO may, at its discretion, require a Customer to install Metering Equipment on the Customer's premises, at the Customer's sole cost, and the Customer shall comply with such a request in a timely manner. If the Customer refuses or fails to comply with such a request, the AESO may request, and the Customer shall grant, access at any reasonable time to the Customer's premises so the AESO may enter the Customer's premises to install Metering Equipment, at the Customer's sole cost.

12.4 The AESO may request, and the Customer shall grant, access at any reasonable time to the Customer's premises so the AESO may, at the Customer's sole cost, enter the Customer's premises to read any Metering Equipment installed on the Customer's premises.

12.5 The Customer may request, at the Customer's sole cost, that the AESO arrange for testing of any Metering Equipment.

12.6 The AESO may require testing of Metering Equipment at any time. In the event that the Metering Equipment meets the System Accuracy Standard, the AESO shall bear the cost of such testing. In the event that the Metering Equipment does not meet the System Accuracy Standard, the Customer shall bear the costs of such testing and the required recalibration.

12.7 If a Dispute should arise with respect to the Metering Equipment or Metering Equipment data, the Dispute shall be resolved in accordance with the provisions of Article 16 below.

12.8 Metering signals in the form of energy pulses, reactive energy pulses, analog values of energy and reactive energy can be provided to the Customer, upon written request and at the Customer's cost. This cost shall be included in the Customer's Statement of Accounts.

12.9 All Customers shall provide Metering Equipment that measures Metered Demand in fifteen (15) minute intervals. The AESO may, at its discretion, require a Customer to provide Metering Equipment that is capable of measuring Metered Demand at one (1) minute intervals or at such other intervals as may be determined by the AESO.

12.10 The Customer shall make reasonable efforts to provide the AESO, in accordance with the E&GI Act and the TAOPS, the following data:

(a) fifteen (15) minute interval POC metering data; or

(b) if requested by the AESO, one (1) minute interval POC metering data.

The Customer shall provide the metering data set out above, for the previous day, by 12:00 p.m. of the next business day. Revenue class meters will be used for billing purposes, energy purchases and sales and system support service purchases.

12.11 Subject to Paragraph 12.12, failure to comply with the metering requirements set out in this Article 12 shall result in the AESO withholding, suspending or terminating System Access Service.

12.12 The AESO shall not withhold, suspend or terminate System Access Service under paragraph 12.11 unless and until the metering non-compliance has been resolved in accordance with the provisions of Article 16, the Customer has failed to adhere to the arbitrator's decision in a timely manner and the AESO has provided the Customer with five (5) days prior written notice of its intention to withhold, suspend or terminate System Access Service.

ARTICLE 13
SERVICE INTERRUPTIONS AND FORCE MAJEURE

13.1 Although precautions are taken to guard against System Access Service interruptions, the AESO does not guarantee uninterrupted System Access Service. The AESO is not responsible for interruptions which occur as a result of:

(a) scheduled or planned facility maintenance activities;

(b) construction, commissioning and facility testing activities;

(c) unscheduled or unplanned events (such as, but not limited to, emergency equipment maintenance and Emergencies);

(d) Force Majeure;

(e) breaches of obligations owed to the AESO by its suppliers or Customers; or

(f) as otherwise expressly allowed by a Rate Schedule.

13.2 Whenever System Access Service has been interrupted, diminished or reduced for reasons other than a breach of these Terms and Conditions by the Customer, the AESO shall make all reasonable efforts to ensure that service is restored as soon as practicable after the interruption, diminution or reduction.

13.3 The Customer's obligations to pay for System Access Service, to provide information and to maintain Interconnection Requirements shall not be affected during, or as the result of, any event of Force Majeure or other System Access Service interruption expressly contemplated under this Tariff.

ARTICLE 14
LIMITATION OF LIABILITY

14.1 Notwithstanding anything to the contrary contained in these Terms and Conditions, no action lies against the AESO, the ISO, nor its affiliates, directors, officers or employees ("AESO Persons") and AESO Persons are not liable for any act or omission carried out or purportedly carried out in accordance with this Tariff ("AESO Person Act") unless the AESO Person Act constitutes willful misconduct, negligence, breaching of contract or if the AESO Person Act is not carried out in good faith. If a AESO Person is liable to another person for a AESO Person Act, then the AESO Person is liable for only Direct Loss or Damage suffered or incurred by that other person.

ARTICLE 15
INCREASES, REDUCTIONS OR TERMINATION OF CONTRACT CAPACITY

15.1 In the event that a Customer desires to increase the Contract Capacity in its System Access Service Agreement at an existing POD or POS, the Customer must execute an amended System Access Service Agreement. If new facilities or upgrades are required to provide the new service or to provide the amended service level, the requirements for a Customer Contribution shall apply and the provisions of Article 8 shall be applicable.

15.2 The Contract Capacity for a new POS established by the AESO shall not exceed the sum of the MCR of all generators connected to the AIES by the new POS less the sum of all gross loads that offset the energy delivered to the AIES from that POS under normal operating conditions.

15.3 (a) Subject to paragraphs (b) and (c), the Metered Demand for a Customer taking service under Rate Schedule DTS or Rate Schedule STS shall not exceed the lesser of:

(i) 110% of the Contract Capacity;

(ii) the Rated Capacity of any transmission facilities comprising its interconnection; or

(iii) the Physical Capacity of any transmission facilities comprising it's interconnection.

In the event that the foregoing is not complied with, the AESO shall have the right to discontinue the applicable System Access Service until the Customer installs equipment to limit its Metered Demand.

(b) A DTS Customer may temporarily exceed the level stipulated in subparagraph 15.3(a)(i) to the extent it has in place a System Access Service Agreement for an Opportunity Service at the applicable POD.

(c) Subject to subparagraph 15.3(d) an STS customer may temporarily exceed the level stipulated in subparagraph 15.3(a)(i), with the AESO's consent obtained on a minimum twenty-four (24) hours' notice, provided that the AESO determines that the transmission system can safely accommodate the proposed energy without risk of disturbance to other AESO customers.

(d) Under exceptional circumstances, the AESO may allow a reduction to the notice provisions for STS customers with frequently repeated transactions of similar size and duration, but under no circumstance will a notice period of less than one (1) hour be accepted.

15.4 At least once per year, the AESO will review the Contract Capacity of STS customers. The AESO may reduce a customer's STS Contract Capacity to:

(a) The mean metered power delivered to the AIES in the preceding twelve (12) months; or

(b) For low capacity factor generators, the mean metered power delivered to the AIES over recurrent periods that are shorter than twelve (12) months, as determined by the AESO

if such deliveries are more than 10% below the existing Contract Capacity or as mutually agreed to between the Customer and the AESO.

15.5 System Access Service Agreements between the AESO and Customers who operate Regulated Generating Units shall be terminated on the PPA Effective Date, with the exception of Regulated Generating Units that are not sold at the PPA auction and the Regulated Hydro Generating Units outlined in Appendix E.

15.6 System Access Service Agreements with an effective date after the PPA Effective Date between the AESO and Customers who operate Regulated Generating Units or who have entered into a Power Purchase Arrangement with the owner of a Regulated Generating Unit shall terminate at the end of the base life year of the Regulated Generating Unit as outlined in Appendix E with the exception of the following Regulated Generating Units listed below:

(a) Rossdale Units 8, 9 and 10's deemed base life year shall be 2003; and

(b) Rainbow Units 1, 2 and 3's deemed base life year shall be 2005;

15.7 Reductions of Contract Capacity at a POD or a POS will be made five (5) years after receipt of written notice from the Customer. The Contract Capacity immediately following the five (5) year notice period shall be the maximum of:

(a) the pre-notice Contract Capacity less the reduction of Contract Capacity requested by the Customer; or

(b) the highest Metered Demand during the notice period less the reduction of Contract Capacity requested by the Customer.

15.8 Separate written notice must be provided for increases or reductions of Contract Capacity at each respective POD and POS at a single transmission station; no net reductions will be accepted or effected.

ARTICLE 16
DISPUTE RESOLUTION

16.1 A Dispute shall be referred to a senior officer from each of the AESO and the relevant Customer for resolution.

16.2 If the Dispute has not been resolved within thirty (30) days after referral to the senior officers, either the AESO or the Customer may require, by written notice, that the Dispute be resolved through arbitration. The AESO shall advise the AEUB of any matter going to arbitration within thirty (30) days of the matter being referred to arbitration. The parties shall appoint a mutually satisfactory arbitrator within ten (10) days of the notice to resolve the Dispute through arbitration. In the event that the parties cannot agree on a single arbitrator within ten (10) days, each party shall appoint an arbitrator within ten (10) days thereafter by written notice, and the two arbitrators shall together appoint a third arbitrator. In the event that a tribunal is required, the third arbitrator shall be appointed within twenty (20) days of written notice for arbitration. The arbitrator or tribunal shall render a decision within thirty (30) days of the last appointment. The AESO shall advise the AEUB of the results of the arbitration within thirty (30) days of the Arbitrator's decision. The AESO shall also furnish the AEUB with a list of parties potentially affected by the results of the arbitration. The arbitration shall be conducted in accordance with the Arbitration Act (Alberta), as amended from time to time. In the event of a conflict between these Terms and Conditions and the Arbitration Act, these Terms and Conditions shall prevail.

16.3 Any interested party adversely and unduly affected by the decision of an arbitrator or a tribunal is entitled to make an application to the AEUB requesting a clarification or change to these Terms and Conditions.

16.4 Pending resolution of any Dispute, the AESO and the Customer shall continue to perform their respective obligations under this Tariff.

ARTICLE 17
MAINTENANCE OF RECORDS

17.1 The AESO shall maintain records for a period of ten (10) years relating to those matters associated with the Tariff, such as capital costs of facilities, which require such level of data retention to perform necessary calculations or otherwise provide necessary information, and for any other matter, the AESO shall maintain records for a period of six (6) years. Data required to verify any billing information provided by the AESO may be made available to Customers during regular business hours and the Customer will be responsible to pay for all of the costs of retrieval and provision of the data.

ARTICLE 18
COSTS ASSOCIATED WITH REBILLING

18.1 When invoices to Customers have to be recalculated and reissued forty-five (45) days or more after end of the applicable billing period as a result of:

(i) unavailable or incomplete meter data, or

(ii) inaccurate estimates of meter data,

(iii) reconciliation with updated estimates of meter data,

the cost of recalculating and reissuing the affected Statement of Account shall be recovered from the Customer taking service from the relevant Metering Equipment. The AESO shall charge $1,000 for each recalculated and reissued invoice.

ARTICLE 19
NOTIFICATIONS

19.1 All notices given or served upon the AESO in accordance with this Tariff shall be in writing and shall be marked "Important" and given by personal service, telefax or by registered letter addressed to:

AESO
Attention: Manager, Customer Service
900, 736 – 8 Ave SW
Calgary, Alberta, T2P 1H4

or by telefax addressed to:
AESO
Attention: Manager, Customer Ser...
Fax (403) 266-2959

19.2 All notices given or served upon the Customer in accordance with this Tariff shall be in writing served by personal service, registered letter or telefax and sent to the address or addresses shown for such Customer in the relevant System Access Service Agreement.

ARTICLE 20
SPRDA GENERATORS

20.1 Generating Units constructed under the *Small Power Research and Development Act* (Alberta) ("SPRDA") are exempt from the provisions of Rate Schedule STS to the extent of the volume of energy sales which they conduct under contracts specifically executed pursuant to the provisions of the SPRDA.

ARTICLE 21
PEAK METERED DEMAND WAIVER

21.1 The AESO may, in its sole discretion, waive the Metered Demand set in a Billing Period or any prior Billing Periods for the purposes of calculating the Billing Capacity when such level of Metered Demand was caused by one of the following:

(a) Commissioning as defined in the Article 1;

(b) activities required to repair and maintain transmission facilities;

(c) pre-scheduled activities required to repair and maintain distribution facilities;

(d) load restoration activities following an outage of transmission or distribution facilities or caused by an Emergency;

(e) an event of Force Majeure; or

(f) compliance with a dispatch instruction from the System Controller during an Emergency.

ARTICLE 22
TRANSMISSION SYSTEM EXPANSION

22.1 Except in exceptional circumstances, the following material new transmission facilities shall be competitively procured:

(a) facilities with a capital construction cost of $10 million dollars or more;

(b) facilities of a voltage of 240kV or higher; or

(c) interconnections with neighboring Control Areas.

22.2 The AESO reserves the right to directly assign the construction of a new transmission facility in the event that the AESO determines that the costs of administering a competitive procurement process would outweigh the benefits thereof.

22.3 Subject to Paragraphs 22.1 and 22.2, any Customer whose interconnection to the AIES requires the construction of material new transmission facilities, whose load or generation equals or exceeds 5 MW and who is transmission-interconnected, may elect to have the facilities competitively procured by the AESO. Any Customer electing to have the AESO competitively procure transmission facilities which do not meet one or more of the criteria listed in Paragraph 22.1 shall pay all reasonable out-of-pocket expenses (including, but not limited to, legal fees, technical consultants' fees and regulatory expenses) incurred by the AESO while conducting the competitive procurement process. The AESO shall be entitled to require the payment of deposits from time to time during the course of the competitive procurement process and the AESO shall be entitled to withhold continuation of the process until such time as deposits are made.

22.4 In the event that a Customer requires facilities to be built in addition to those which the AESO would otherwise provide ("Optional Facilities"), the Customer will be required to pay 100% of the cost of those additional facilities, however the Customer may choose to have those Optional Facilities competitively procured by the AESO, subject to Paragraph 22.1 and in accordance with Paragraph 22.3.

22.5 The AESO shall procure all transmission facilities. No Customer shall, without the prior written consent of the AESO, directly procure transmission facilities, whether competitively or otherwise, except for transmission facilities directly assigned by the AESO.

ARTICLE 23
MISCELLANEOUS

23.1 Each respective System Access Service Agreement executed by the AESO hereunder shall be binding on any subsequent ISO) for the length of its term.

23.2 A Customer can assign its System Access Service Agreement or any rights thereunder to another Customer who is qualified for the service available under such agreement, but only with the consent of the AESO, such consent not to be unreasonably withheld.

23.3 In the event of any conflicts between the provisions of these Terms and Conditions, and the provisions of the Rate Schedules, the provisions of these Terms and Conditions shall govern.

23.4 Customers shall comply with dispatches and directives of the System Controller which are required for performance of Customers' obligations hereunder in real-time, including, without limitation, those related to Interconnection Requirements and provision of System Support Services.

ARTICLE 24

ANCILLARY SERVICES

24.1 During a state in which the AIES lacks sufficient Ancillary Services and for the purposes of maintaining system security, the System Controller may require a Customer to operate its generating unit to provide Ancillary Services. For the period during which the conscription persists, Customers required to provide Ancillary Services shall be compensated as provided in Article 24.2 or Article 24.3, whichever is applicable.

24.2 If at the time the Customer is required to provide Ancillary Services the Customer has an existing contract with the AESO, either directly or indirectly, to provide the Ancillary Services in question (the "Existing Contract"), then the amount to be paid to the Customer by the AESO for the Ancillary Services shall be determined according to the terms of the Existing Contract.

24.3 If at the time the Customer is required to provide an Ancillary Service and the Customer does not have an Existing Contract, then the amount to be paid to the Customer by the AESO in respect of each Ancillary Service provided shall be the greater of:

(a) The sum, over all hours during which the Customer is required to provide the Ancillary Service pursuant to Article 24.1, of the product of the hourly MW dispatch and the highest price paid in the hour to Customers providing the Ancillary Service pursuant to Article 24.2; or

(b) The sum, over all hours during which the Customer is required to provide the Ancillary Service pursuant to Article 24.1, of the product of the hourly MW dispatch and 110% of the energy price in the hour as set by the Power Pool of Alberta, plus any additional charges from the Power Pool of Alberta (including but not limited to uplift charges) and charges from the AESO net of pool energy receipts; or

(c) The direct costs incurred by the Customer to provide the required Ancillary Service, net of pool energy receipts, plus ten percent. Direct costs include, but are not limited to, generating unit start-up costs, costs to purchase replacement energy to fulfil Customers' contractual obligations, fuel costs and variable operation and maintenance costs; however, direct costs do not include indirect, incidental, consequential, or special damages arising out of or relating to the Customer providing Ancillary Services. Direct costs also include a prorate of fixed capacity costs and fixed maintenance costs applicable to the conscription period. The pro-rata share shall be calculated using the fraction of hours of providing ancillary services pursuant to Article 24.1 to the total operating hours of the service providing facility in the calendar month. For Customers with Power Purchase Arrangements that have annual start limitations and that are forced to make a start-up in response to a directive from the System Controller, the minimum pro-rata share of fixed costs shall be calculated as the total annual costs, times the number of starts consumed in providing ancillary services, divided by the annual start allowance. Revenues received by Customers, pursuant to the purchase of Power Purchase Arrangements, shall be treated as an offset to the prorate of fixed capacity costs; or

(d) The verifiable net opportunity cost incurred by the Customer to supply the required Ancillary Services taking into account all offsetting revenues from any source, such as pool energy receipts; or

24.4 For the purposes of this Article, MW dispatch means the amount of an Ancillary Service (expressed in MW) that is provided by the Customer in response to a dispatch by the System Controller.

ARTICLE 25
CONFIDENTIALITY

25.1 The AESO:

(a) shall not disclose the Confidential Information to any person except as permitted under this Tariff;

(b) shall only use or reproduce the Confidential Information for the purpose for which it was disclosed or another purpose contemplated in this Tariff;

(c) shall not permit unauthorized persons to have access to the Confidential Information; and

(d) shall only disclose the Confidential Information to those Representatives who need to know the information and have been informed of the confidential nature of the Confidential Information.

25.2 Exceptions to the confidentiality obligations stated in Paragraph 25.1 will be made when:

(a) the disclosure, use or reproduction of information if the relevant information is at the time generally and publicly available other than as a result of breach of confidence by the AESO;

(b) the disclosure, use or reproduction of information with the consent of the person or persons who provided the relevant information;

(c) the disclosure, use or reproduction of information to the extent the Confidential Information:

(i) must be disclosed by law to any agent, government or governmental body, authority or agency having jurisdiction over the Transmission Authority;

(ii) must be disclosed to the Power Pool of Alberta or System Controller for the purposes of the Transmission Administration fulfilling its duties under the *EUA* (Alberta); and

(iii) must be disclosed to a TFO for the purposes of the AESO fulfilling its duties under the *EUA* (Alberta). All information provided to a TFO shall be subject to the confidentiality provisions in the TFO's Terms and Conditions of service.

the disclosure, use or reproduction of information if required in connection with legal proceedings, arbitration, expert determination or other dispute resolution mechanism relating to this Tariff;

(d) the disclosure of information if required to protect the safety of personnel or equipment, or to protect the reliability of the AIES; and

(e) the disclosure, use or reproduction of information as an unidentifiable component of an aggregate of information.

25.3 In the case of a request or demand for disclosure under Paragraph 25.2(c)(i) or Paragraph 25.2(d), the AESO will provide notice to those affected by the request or demand as soon as reasonably practicable, so as to afford the opportunity to challenge such request or demand or seek injunctive relief or protection from the request or demand.

25.4 No provision of this Tariff obligates the Customer to treat its own information and agreements with the AESO as confidential.

Appendix "A"

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Appendix "B"

System Access Service Agreement Proformas

SYSTEM ACCESS SERVICE AGREEMENT
DEMAND TRANSMISSION SERVICE

The following constitute the terms pursuant to which the Independent System Operator, **a corporation carrying on business under the trade name** Alberta Electric System Operator (AESO), shall provide System Access Service to the Customer. (Defined terms used herein without definition shall have the meanings ascribed thereto in the Terms and Conditions of the AESO's Tariff).

1. TYPE OF SERVICE

Service under this Agreement shall be provided pursuant to Rate Schedule Demand Transmission Service (DTS).

2. POINT OF INTERCONNECTION WITH THE TRANSMISSION SYSTEM

(a) Point of Supply (POD): The POD shall be [description, e.g. relative to Substation]

(b) Location:
Township_____ Range_____ W____M

3. CONTRACT CAPACITY

"x" MW

4. COMMISSIONING PERIOD FOR NEW FACILITIES, IF ANY:

5. EFFECTIVE DATE

_____ __, 2001

6. CUSTOMER CONTRIBUTION

The Customer Contribution charge is $_____.

Number of Commitment terms _____ x 5 equals _____ years.

7. RATES AND TERMS OF SERVICE

The supply of System Access Service pursuant to this Agreement, and the Customer's obligations with respect to connection and supply of System Support Services, shall be subject to the AESO's Tariff, in particular to the Rate Schedule referenced under Paragraph 1.

8. NOTICES

Notices sent to the Customer pursuant to this Agreement shall be as follows:

Invoices: Attention: _____
Address: _____
_____ _____
_____
Fax: _____

All other notices: Attention: _____
Address: _____
_____
_____
Fax: _____

9. [Optional Clause for Customer designated to provide under-frequency load shed]

_____MW of load is connected by an under-frequency load shed relay set to trip at ____Hz.

By executing in the space below, the Customer and the AESO agree to the foregoing provisions.

Independent System Operator a corporation carrying on business under the trade name Alberta Electric System Operator

Per: _____ Date: _____
Tony Demassi
Director, Customer Relations

Per: _____ Date: _____
Name: _____
Title: _____

Per: _____ Date: _____
Name: _____
Title: _____

DEMAND OPPORTUNITY SERVICE
STAGE 1 APPLICATION FOR OPPORTUNITY SERVICE

Stage 1 Application for Demand Opportunity Service (DOS)
Preliminary Assessment

The "Applicant", noted below, requests a preliminary assessment of the availability of Opportunity Service for the use described herein. The Applicant should be familiar with the information on Opportunity Service that appears on the AESO's website, including the AESO's Business Practices for Demand Opportunity Service and the AESO's Term and Conditions of Service. This application does not bind the AESO or the Applicant to any contractual arrangement. There is no fee at Stage 1.

IDENTIFICATION OF END USER AND CUSTOMER

End User Name:_____

Customer Name:_____
(Must be an existing DTS Customer of the AESO)

Primary Contact: Name: _____ Company: _____

(May be the end user or the Customer at Stage 1; however, the Stage 2 application must be made by the AESO's Customer.)

Phone Number: _____ Fax number: _____ Email Address: _____

Facility Name: _____
Facility Location: LSD____**SEC**_____**TWP**_____**RGE**_____**MER**____
Connected AIES Substation (Name and Number): _____

Point of Delivery (POD): _____
(Description of the Point of Delivery)

TECHNICAL AND COMMERCIAL INFORMATION

The following preliminary information is required.

- Earliest date Opportunity Service is expected to be used:_____
- Requested Opportunity Capacity: _____MW (Demand in excess of DTS Contract Capacity)
- Proposed use of the electricity to be obtained under DOS, and anticipated consumption profile:

  Please provide this, labeled "Schedule A".
- *Eligibility:* ***Please read the Commercial Eligibility Criteria of the AESO's Business Practices for Demand Opportunity Services (DOS)*** *and provide a brief explanation, labeled "Schedule B", of how the proposed use of DOS meets the criteria.*
- Referring to the Commercial Eligibility Criteria, which of the following applies? (Check one):

1. Alternative Source of Energy ☐ 2. No Alternative Source of Energy ☐ 3.Generator Maintenance ☐

- What will the applicant do if DOS is not available as requested?_____
___
- For what period of time does the applicant expect the qualifying criteria to persist?___
_____

CONFIDENTIALITY

Prior to submitting this application, the applicant may request the AESO to sign a confidentiality agreement. May the AESO disclose information from this application to the interconnecting Transmission Facility Owner, on a need-to-know basis? Yes _____
_____No_____

DEMAND OPPORTUNITY SERVICE
STAGE 1 APPLICATION FOR OPPORTUNITY SERVICE

Stage 1 Application for Demand Opportunity Service (DOS) -- Preliminary Assessment

ATTACHMENTS TO BE PROVIDED BY THE APPLICANT

- Schedule A: Proposed use of the electricity to be obtained under DOS, and anticipated consumption profile
- Schedule B: Explanation of how the proposed use of DOS meets the Commercial Eligibility Criteria

The applicant acknowledges that this document is not a contract between itself and the Alberta Electric System Operator.

Applicant:_____ Date: _____

(The applicant may be the end user or the Customer at Stage 1; however, the Stage 2 applicant must be a DTS Customer of the AESO.)

Name: _____Title: _____

Please complete and send to Alberta Electric System Operator .
Mail: 900, 736 – 8 Avenues S.W.
Calgary, Alberta T2P 1H4
Fax: (403) 266-2959

DEMAND OPPORTUNITY SERVICE
STAGE 2 APPLICATION FOR OPPORTUNITY SERVICE

Stage 2 Application for Demand Opportunity Service (DOS)
Pre-qualification

It is suggested that a Stage 1 Application (preliminary assessment) be made before making this Stage 2 Application. The applicant should be familiar with the information on Opportunity Service that appears on the AESO's website, including the AESO's Business Practices for Demand Opportunity Service, the AESO's Terms and Conditions of Service, and the Rate Schedules. This application does not bind the AESO or the applicant to any contractual terms or conditions. A non-refundable fee of $5000.00 is payable with this application.

IDENTIFICATION OF APPLICANT AND THE END USER

Applicant: _____
(Must be an existing DTS Customer of the AESO)

End User Name: _____
(Need not be a direct Customer of the AESO)

Primary Contact: Name: _____ **Company:** _____
(May be the end user, at the discretion of the Applicant.)

Phone: _____ **Fax:** _____ **Email:** _____

Facility Name: _____
Facility Location: LSD____**SEC**____**TWP**____**RGE**____**MER**____
Connected AIES Substation (Name and Number): _____

Point of Delivery (POD): _____
(Description of the Point of Delivery)

Has a Stage 1 Application been submitted for this proposed use of DOS? Yes _____ **No** _____

TECHNICAL AND COMMERCIAL INFORMATION

The following information is required in order for the AESO to assess whether the proposed use of DOS complies with the AESO's Terms and Conditions of Service and meets the technical and commercial eligibility criteria.

- **Earliest date Opportunity Service is expected to be used:** _____
- **Requested Opportunity Capacity:** _____ MW (Maximum demand in excess of DTS Contract Capacity)
- **Type of Opportunity Service expected to be used:** DOS 7 minute ___DOS 1 Hour ___DOS Standard___
  (This indication does not preclude the use of other types of Opportunity Service.)
- **Technical Information:** *Please provide the following, labeled* ***"Schedule A".***
  1. Load Characteristic (static, synchronous machine, or induction machine).
  2. Approximate load factor.

3. Expected power factor.

- **Commercial Information**: ***Please read the Commercial Eligibility Criteria of the AESO's Business Practices for Demand Opportunity services (DOS)*** *and* ***provide a comprehensive Business Case, labeled "Schedule B",*** *demonstrating that the proposed use of DOS complies with these criteria. The Business Case must provide enough information to satisfy the AESO that the proposed use of electricity under DOS would not occur at the standard rate schedule (DTS). The Business Case normally pertains to the end user's commercial circumstances, and the end user must be prepared to provide any additional information that the AESO reasonably requests.*
- For what period of time does the applicant expect the qualifying criteria to persist?___

_____

(This information does not limit the pre-qualification to this time period.)

DEMAND OPPORTUNITY SERVICE
STAGE 2 APPLICATION FOR OPPORTUNITY SERVICE

Stage 2 Application for Demand Opportunity Service (DOS) – Pre-qualification

CONFIDENTIALITY

Prior to submitting this application, the applicant may request the AESO to sign a confidentiality agreement. May the AESO disclose information from this application to the interconnecting Transmission Facility Owner, on a need-to-know basis? Yes _____No_____

ATTACHMENTS TO BE PROVIDED BY THE APPLICANT

- Schedule A: Technical information describing the proposed use of DOS
- Schedule B: Business Case demonstrating that the proposed use of DOS meets the Commercial Eligibility Criteria

The Applicant confirms that the contents of this application are true.

Applicant:_____ Date:_____
(The applicant must be a DTS Customer of the AESO.)

Name: _____Title: _____

Please complete and send to Alberta Electric System Operator
Mail: 900, 736 – 8 Avenues S.W.
Calgary, Alberta T2P 1H4
Fax: (403) 266-2959

The Alberta Electric System Operator acknowledges that this application was received on the indicated date, together with the prescribed fee.

_____ Fee paid: $___
(Date)

Signature: _____

Name: _____Title: _____

Alberta Electric System Operator Internal Use Only

Corporate Finance

Application approved or denied:_____

Signature:_____Date:_____

Name:_____Title:_____

Technical Services Operational Planning

Application approved or denied:_____

Approved application checklist: Loss Factor (Y/N):_ Pre-qualify List addition (Y/N):_____

Signature:_____Date:_____

Name:_____Title:_____

SYSTEM ACCESS SERVICE AGREEMENT
DEMAND OPPORTUNITY SERVICE

	OP-224
Alberta Electric System Operator *Operating Policy OP-224* **Opportunity Service**	**Issue Date:** 2002-05-01 **Effective Date:** 2002-05-01 **Expiry Date:** Annual **Revision No.:** 1

Appendix A: DOS Request

_____ - _____ Check box if this Request overlaps with a previous DOS Request or DOS Transaction ☐

Pre-qualification Number | Request number provided by Customer

The Customer is to complete this document, and fax it to the System Controller to request a DOS Transaction. The Customer must follow up by phoning the SC. (Fax: 403-261-7864) (Ph: 403-233-6420)

Demand Opportunity Service (DOS), according to the terms herein, will be available only after the System Controller approves this DOS Request..

Identification

_____ requests Opportunity Service (subject to confirmation of available
Customer or Customer's Agent

capacity) in accordance with the Pre-qualification granted by the Alberta Electric System Operator, identified by Pre-qualification Number shown above, at _____

_____
Description of the Point of Delivery

Terms of Transaction

The requested service is (indicate one): ___DOS Standard; ___DOS 7 minutes, ___DOS One hour

The transaction is to begin on: _____ (Start Date) at _____ (Start time)

The transaction will be completed on: _____ (End Date) at _____ (End time)

A DOS Transaction must start and end at the top of an hour, and cannot start within 60 minutes of the time the DOS Request is faxed. The minimum Term is 8 hours; End Date must occur in the same calendar month as the Start Date

The requested Capacity is _____ MW (cannot exceed the Opportunity Capacity)

Applicant's Endorsement

Submitted by: _____ (Customer's Representative (please print)) on _____ (date) at _____ (time)

Signature: _____ (Customer's Representative) Phone: _____ Fax: _____

Approval/Denial by the System Controller..

Submitted by: _____ (System Controller's Representative (please print)) on _____ (date) at _____ (time)

Signature: _____ (System Controller's Representative)

Approved: ☐ Denied: ☐ If denied, please indicate the reason below:

The request does not comply with the SC's information on pre-qualified DOS customers: ☐

The requested Opportunity Capacity is unavailable at the time requested: ☐

System Controller's comments: _____

_____

SYSTEM ACCESS SERVICE AGREEMENT
EXPORT SERVICE

The following constitute the terms pursuant to which the Independent System Operator, a corporation carrying on business under the trade name Alberta Electric System Operator (AESO) shall provide System Access to the Customer: (Defined terms used herein without definition shall have the meanings ascribed thereto in the Terms and Conditions of the AESO's Tariff).

1. TYPE OF SERVICE

Service under this contract shall be pursuant to Rate Schedule Export Service (ES).

2. POINT OF EXPORT

❑ British Columbia Intertie ❑ Saskatchewan Intertie

3. EFFECTIVE DATE

_____ __, 2001

4. TERM

_____Days [Months]

5. RATES AND TERMS OF SERVICE

The supply of System Access Service under this Agreement shall be pursuant to the AESO's Tariff.

6. NOTICES

Notices sent to the Customer pursuant to this Agreement shall be as follows:

Invoices:	Attention:	_____
	Address:	_____
		_____
		_____
	Fax:	_____
All other notices:	Attention:	_____
	Address:	_____
		_____
		_____
	Fax:	_____

By executing in the space below, the Customer and the AESO agree to the foregoing provisions.

Independent System Operator a corporation carrying on business under the trade name Alberta Electric System Operator

Per: _____ Date: _____
Tony Demassi
Director, Customer Relations

Per: _____ Date: _____
Name: _____
Title: _____

Per: _____ Date: _____
Name: _____
Title: _____

SYSTEM ACCESS SERVICE AGREEMENT
SUPPLY TRANSMISSION SERVICE

The following constitute the terms pursuant to which the Independent System Operator, **a corporation carrying on business under the trade name Alberta Electric System Operator** (AESO) shall provide System Access to the Customer. (Defined terms used herein without definition shall have the meanings ascribed thereto in the Terms and Conditions of the AESO's Tariff).

1. TYPE OF SERVICE

System Access Service shall be provided pursuant to Rate Schedule Supply Transmission Service (STS).

2. POINT OF INTERCONNECTION WITH THE TRANSMISSION SYSTEM

(a) Point of Supply (POS): The POS shall be [description, e.g. relative to Substation]

(b) Location:
Township_____ Range_____ W____M

3. CONTRACT CAPACITY

"x" MW

4. COMMISSIONING PERIOD FOR NEW TRANSMISSION FACILITIES, IF ANY

5. EFFECTIVE DATE

_____ __, 2001

6. CUSTOMER CONTRIBUTION

The Customer Contribution charge is $_____.

7. RATES AND TERMS OF SERVICE

The supply of System Access Service pursuant to this Agreement and the Customer's obligations with respect to connection and supply of System Support Services shall be subject to the AESO's Tariff, in particular to the Rate Schedule referenced under Paragraph 1.

8. NOTICES:

Notices sent to the Customer pursuant to this Agreement shall be as follows:

Invoices:	Attention:	_____
	Address:	_____
		_____
		_____
	Fax:	_____
All other notices:	Attention:	_____
	Address:	_____
		_____
		_____
	Fax:	_____

By executing in the space below, the Customer and the AESO agree to the foregoing provisions.

Independent System Operator a corporation carrying on business under the trade name Alberta Electric System Operator

Per: _____ Date: _____
Tony Demassi
Director, Customer Relations

Per: _____ Date: _____
Name: _____
Title _____

Per: _____ Date: _____
Name: _____
Title _____

SYSTEM ACCESS SERVICE AGREEMENT
IMPORT SERVICE

The following constitute the terms pursuant to which the Independent System Operator, **a corporation carrying on business under the trade name Alberta Electric System Operator** (AESO) shall provide System Access to the Customer. (Defined terms used herein without definition shall have the meanings ascribed thereto in the Terms and Conditions of the AESO's Tariff).

1. TYPE OF SERVICE

Service under this contract shall be pursuant to Rate Schedule Import Service (IS).

2. POINT OF INTERCONNECTION WITH THE TRANSMISSION SYSTEM

❑ British Columbia Intertie ❑ Saskatchewan Intertie

3. EFFECTIVE DATE

_____ __, 2001

4. TERM

_____Days

5. RATES AND TERMS OF SERVICE

The supply of System Access Service pursuant to this Agreement shall be subject to the AESO's Tariff, in particular to the Rate Schedule referenced under Paragraph 1.

6. NOTICES

Notices sent to the Customer pursuant to this Agreement shall be as follows:

Invoices: Attention: _____
Address: _____
_____
_____
Fax: _____

All other notices: Attention: _____
Address: _____
_____
_____
Fax: _____

By executing in the space below, the Customer and the AESO agree to the foregoing provisions.

Independent System Operator a corporation carrying on business under the trade name Alberta Electric System Operator

Per: _____ Date: _____
Tony Demassi
Director, Customer Relations

Per: _____ Date: _____
Name: _____
Title: _____

Per: _____ Date: _____
Name: _____
Title: _____

Appendix "C"

Construction Commitment Agreement Proforma

THIS AGREEMENT is effective on _____ (the "Effective Date")

BETWEEN:

Independent System Operator a corporation carrying on business under the trade name Alberta Electric System Operator
(hereinafter referred to as the "AESO")

-and-

(Insert name of party)
A corporation incorporated under the Business Corporations Act (Insert Jurisdiction)
(hereinafter referred to as the "Customer")

INTRODUCTION

1. The Customer has requested System Access Service from AESO and intends to enter into a System Access Service Agreement with the AESO. The granting of System Access Service to the Customer will necessitate the construction of new transmission facilities and a commitment by the Transmission Administrator in relation to the expenditure of capital for such construction (the "Proposed Project").

2. Upon execution of this Construction Commitment Agreement, the Transmission Administrator shall begin implementing plans to complete the Proposed Project. Both the Transmission Administrator and its contractors must be held harmless from any negative financial consequences emanating from a decision by the Customer to discontinue, postpone or cancel the Proposed Project.

AGREEMENT

1. The AESO and the Customer agree to the following:

   (a) This Agreement shall take effect on the Effective Date and shall remain in effect until execution of the System Access Service Agreement by the AESO and the Customer;

   (b) If the Customer terminates the Proposed Project or fails to execute the System Access Service Agreement within 30 days after the completion of

the Proposed Project, the Proposed Project shall be deemed to have been cancelled and the Customer shall immediately reimburse the AESO for the aggregate amount of costs and expenses, as well as any losses, damages, penalties or other claims it may incur or be subject to howsoever arising from the Proposed Project ("Cancellation Costs"), and which are incurred by the AESO or its contractors relating to facilities planning and design, the competitive procurement process (if any), material and right-of-way procurements and construction of the Proposed Project (including without limitation all cancellation penalties and salvage and reclamation costs);

(c) In the event that the Customer terminates the Proposed Project prior to its completion, the AESO shall use, and shall cause its contractors to use, reasonable commercial efforts to minimize the amount of the Cancellation Costs to the extent such is within their control;

(d) The Customer shall pay the Cancellation Costs immediately upon demand by the AESO. In the event that the Customer fails to pay the AESO upon demand, the AESO shall be entitled to charge the Customer 1.5% per month interest on late payment of all amounts due to the AESO; and

(e) In the event that the Customer has not paid all of the Cancellation Costs to the AESO within seven (7) days of receipt by the Customer of the AESO's demand therefor, the AESO shall be entitled to realize fully upon any and all security provided by the Customer as assurance of payment, which security is attached hereto as Schedule "A".

2. The AESO's Tariff form part of this Agreement and in the event of any conflict between the provisions hereof and those of the AESO's Tariff, the AESO's Tariff shall prevail.

THE CUSTOMER AND THE AESO have executed this Agreement on the Effective Date:

Independent System Operator, a corporation carrying on business under the trade name as **Alberta Electric System Operator (AESO).**

Per: _____

Per: _____

(INSERT CUSTOMER'S NAME)

Per: _____

Per: _____

Appendix "D"

Metering Equipment Information

1. For each POS Meter:

   (a) Company identification
   (b) Meter type identification
   (c) Meter serial number
   (d) Date meter installed
   (e) Date meter removed
   (f) Number of elements
   (g) Manufacturer
   (h) Model
   (i) Measurement Canada approval
   (j) Past test dates
   (k) Past results (pass/fail information only)
   (l) Planned test dates

2. For each POS meter recorder:

   (a) Record identification
   (b) Recorder type
   (c) Serial number
   (d) Date installed
   (e) Date removed
   (f) Manufacturer
   (g) Model
   (h) Measurement Canada approval
   (i) Past test dates
   (j) Past results (pass/fail information only)
   (k) Planned test dates

3. For each Current Transformer associated with POS metering:

   (a) Company identification
   (b) Transformer type
   (c) Serial number
   (d) Date installed
   (e) Date removed
   (f) Phase location
   (g) Ratio
   (h) Accuracy
   (i) Manufacturer
   (j) Model
   (k) Measurement Canada approval

4. For each Potential Transformer associated with POS metering:

   (a) Company identification
   (b) Transfer type
   (c) Serial number
   (d) Date installed
   (e) Date removed
   (f) Phase location
   (g) Ratio
   (h) Accuracy
   (i) Manufacturer
   (j) Model
   (k) Measurement Canada approval

Appendix E
Regulated Generating Units

Generating Unit	Owner	Type of Plant	Base Life
Barrier #1	TAU	Hydro	2013
Battle River #3	AE	Coal-fired thermal	2009
Battle River #4	AE	Coal-fired thermal	2009
Battle River #5	AE	Coal-fired thermal	2021
Bearspaw #1	TAU	Hydro	2013
Bighorn #1	TAU	Hydro	2032
Bighorn #2	TAU	Hydro	2032
Braseau #1	TAU	Hydro	2025
Braseau #2	TAU	Hydro	2025
Cascade #1	TAU	Hydro	2013
Cascade #2	TAU	Hydro	2013
Clover Bar #1	EPGI	Gas-fired thermal	2010
Clover Bar #2	EPGI	Gas-fired thermal	2010
Clover Bar #3	EPGI	Gas-fired thermal	2010
Clover Bar #4	EPGI	Gas-fired thermal	2010
Genesee #1	EPGI	Coal-fired thermal	2029
Genesee #2	EPGI	Coal-fired thermal	2029
Ghost #1	TAU	Hydro	2013
Ghost #2	TAU	Hydro	2013
Ghost #3	TAU	Hydro	2013
Ghost #4	TAU	Hydro	2013
Horseshoe #1	TAU	Hydro	2013
Horseshoe #2	TAU	Hydro	2013
Horseshoe #3	TAU	Hydro	2013
Horseshoe #4	TAU	Hydro	2013
H.R. Milner	AE	Coal-fired thermal	2012
Interlakes #1	TAU	Hydro	2013
Kananaskis #1	TAU	Hydro	2013
Kananaskis #2	TAU	Hydro	2013
Kananaskis #3	TAU	Hydro	2013
Keephills #1	TAU	Coal-fired thermal	2023
Keephills #2	TAU	Coal-fired thermal	2023
Pocaterra #1	TAU	Hydro	2013
Rainbow #1	AE	Gas turbine	2005
Rainbow #2	AE	Gas turbine	2005
Rainbow #3	AE	Gas turbine	2005
Rossdale #8	EPGI	Gas-fired thermal	2000
Rossdale #9	EPGI	Gas-fired thermal	2000
Rossdale #10	EPGI	Gas-fired thermal	2000
Rundle #1	TAU	Hydro	2013
Rundle #2	TAU	Hydro	2013

Generating Unit	Owner	Type of Plant	Base Life
Sheerness #1	AE/TAU	Coal-fired thermal	2026
Sheerness #2	AE/TAU	Coal-fired thermal	2026
Spray #1	TAU	Hydro	2013
Spray #2	TAU	Hydro	2013
Sturgeon #1	AE	Gas turbine	1998
Sturgeon #2	AE	Gas turbine	1998
Sundance #1	TAU	Coal-fired thermal	2010
Sundance #2	TAU	Coal-fired thermal	2010
Sundance #3	TAU	Coal-fired thermal	2020
Sundance #4	TAU	Coal-fired thermal	2020
Sundance #5	TAU	Coal-fired thermal	2020
Sundance #6	TAU	Coal-fired thermal	2020
Three Sisters #1	TAU	Hydro	2013
Wabamun #1	TAU	Coal-fired thermal	2003
Wabamun #2	TAU	Coal-fired thermal	2003
Wabamun #3	TAU	Coal-fired thermal	2003
Wabamun #4	TAU	Coal-fired thermal	2003

APPENDIX 2

~~TRANSMISSION ADMINISTRATOR~~ ~~of~~ ALBERTA ELECTRIC SYSTEM OPERATOR

~~2002~~2003 TARIFF

TERMS AND CONDITIONS OF SERVICE

TABLE OF CONTENTS

ARTICLE NO.	DESCRIPTION	PAGE NO.
Article 1	Definitions And Interpretation	3
Article 2	Application Of Tariff	12
Article 3	Use Of Transmission System	13
Article 4	System Support Services	15
Article 5	Interconnection Requirements	16
Article 6	Opportunity Service	18
Article 7	Application Fee	20
Article 8	Security For New Transmission Facilities	23
Article 9	Customer Contribution Policy	24
Article 10	Credit, Statement Of Account And Payment Terms	29
Article 11	Provision Of Information By Customers	31
Article 12	Metering	34
Article 13	Service Interruptions And Force Majeure	36
Article 14	Limitation Of Liability	37
Article 15	Increases, Reductions Or Terminations Of Contract Capacity	38
Article 16	Dispute Resolution	40
Article 17	Maintenance Of Records	41
Article 18	Costs Associated With Rebilling	42
Article 19	Notifications	43
Article 20	~~Sprda~~SPRDA Generators	44
Article 21	Peak Metered Demand	45
Article 22	Transmission System Expansion	46
Article 23	Miscellaneous	47
Article 24	Emergency Provision Of System Support Services	48
Article 25	Confidentiality	50
	APPENDICES	
Appendix A	Intentionally Left Blank	52
Appendix B	System Access Service Agreement Proformas	53
Appendix C	Form of Construction Commitment Agreement	67
Appendix D	Metering Equipment Information	70
Appendix E	Regulated Generating Units	74

ARTICLE 1
DEFINITIONS AND INTERPRETATION

1.1 Unless otherwise expressly provided, any definition of a word or expression in the Act shall apply to the use of such word or expression in this Tariff. Notwithstanding the foregoing, the following terms shall have the following meanings in this Tariff:

"Act" means the *Electric Utilities Act*, ~~R.~~S.A. ~~2000,~~2003, c. E-~~5,~~5.1, as amended.

"AESO" means Alberta Electric System Operator, and is a trade name under which the ISO carries on business in fulfillment of its roles, responsibilities and duties pursuant to the Act.

"AIES" means Alberta's "Interconnected Electric System" as that term is defined in the Act.

"AEUB" means the Alberta Energy and Utilities Board.

"Affiliate" has the meaning ascribed to it in the *Business Corporations Act* (Alberta), S.A. 1981, c. B-15, as amended.

"Apparent Power" means the product of the volts and amperes, comprising both real and reactive power, usually expressed in kilovoltamperes ("kVA") or megavoltamperes ("MVA").

"Application Fee" means the non-refundable interconnection application fee a Customer pays to the ~~Transmission Administrator~~AESO when the Customer submits a request for interconnection to the AIES. Application Fees are set out in Article ~~1.~~7.

"Area Control Error" means the instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias (and time error or unilateral inadvertent energy, if automatic correction for either is part of the AGC);

"Automatic Generation Control" or **"AGC"** means equipment that automatically adjusts a Control Area's generation to maintain its frequency or interchange schedule plus or minus frequency bias.

"Automatic Voltage Regulator" or **"AVR"** means automatic control equipment that changes the Generating Unit excitation level to maintain voltage levels.

"Billing Capacity" shall have the meaning given to that term in Rate Schedule DTS.

"Billing Period" means a period of time starting on the first day of each calendar month at 00:00 hrs. and ending on the last day of the same calendar month at 24:00 hrs., during which a Customer is supplied with System Access Service by the ~~Transmission Administrator~~AESO.

"Business Day" means a day other than a Saturday, a Sunday, a Statutory Holiday, or a Monday when a Statutory Holiday occurs on a Saturday or Sunday and the following Monday is a day during which financial banking privileges are suspended.

"Commercial Operation" means the date upon which a load or Generating Unit begins to operate on the transmission system in a manner which is acceptable to the ~~Transmission Administrator~~AESO and which is expected to be normal for it to so operate, after energization and Commissioning.

"Commissioning" means those limited activities (as approved in advance by the ~~Transmission Administrator~~AESO and subject to written agreement) conducted after interconnection which are required to ensure that a facility can satisfactorily enter Commercial Operation and that a facility meets the ~~Transmission Administrator~~AESO's requirements. Such written agreement will not extend beyond a three month period or a mutually agreed to commissioning period.

"Confidential Information" means information provided to the ~~Transmission Administrator~~AESO which has been specifically identified as being confidential in nature by the provider of such information and information provided pursuant to Article 11 of these T&C's.

"Confirmation Notice" is a notification from the ~~Transmission Administrator~~AESO to a customer that the Customer's system access service application is complete and will be processed.

"Constrained On" means, in respect of a Generating Unit, being dispatched on load while Out of Merit, as a result of a Dispatch Instruction by the System Controller.

"Construction Commitment Agreement" means an agreement to be entered into between the ~~Transmission Administrator~~AESO and a Customer prior to the ~~Transmission Administrator~~AESO arranging for new facilities required to accommodate System Access Service or an increase thereto, as referenced in Paragraph 8.1 hereof.

"Contract Capacity" means the peak demand or supply capability (expressed in MW), as set out in the System Access Service Agreement; it may change only in accordance with the provisions of the terms hereof.

"Control Area" means a geographic area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas, and contributing to frequency regulation of the interconnection, such as the AIES.

"COS" or **"Customer-Owned Substation Credit"** means the credit payable to certain Demand Customers as set forth in Rate Schedule Customer-Owned Substation Credit.

"Customer" is an Eligible Person who takes, or applies to take, System Access Service from the ~~Transmission Administrator~~AESO and satisfies the pre-contract conditions provided in Paragraph 3.1 below.

"Customer's Facilities" means all facilities interconnecting with the AIES on the Customer's side of the POD or POS.

"Customer Contribution" means the amount required to be paid by Customers taking service under Rate Schedule DTS or Rate Schedule STS pursuant to Article 9 hereof.

"Deficiency Notice" is a notification from the ~~Transmission Administrator~~AESO Customer that the Customer's system access service application is deficient and the application will not be processed.

"Demand Customers" are load customers and generation customers, the latter for the purposes of obtaining their back up supply.

"Direct Loss or Damage does not include loss of profit, loss of revenue, loss of production, loss of earnings, loss of contract or any other indirect, special or consequential loss or damage whatsoever arising out of or in any way connected with a ~~Transmission Administrator~~AESO Person Act.

"Dispatch Instruction" means in respect of any Generating Unit, all dispatch instructions issued by the System Controller from time to time, designating such unit to provide System Support Services, by changing the output or manner of operation of a unit, or by another method or procedure, and giving any necessary details as to the service to be provided.

"Dispute" means any dispute, claim or difference which arises in respect of the Tariff between the ~~Transmission Administrator~~AESO and the Customer.

"Distributor" means a party providing "distribution access service" as defined in the Act.

"DOS" or **"Demand Opportunity Service"** means service under any one of Rate Schedules Demand Opportunity Service (DOS 7 Minutes), Demand Opportunity Service (DOS 1 Hour), Demand Opportunity Service (DOS Term).

"DTS" or **"Demand Transmission Service"** means service under Rate Schedule Demand Transmission Service.

"E&GI Act" means the *Electricity and Gas Inspection Act* (Canada) and regulations made thereunder, as amended from time to time, or such replacement legislation as may be enacted.

"Eligible Person" means any of the following: the owner of a Generating Unit; the owner of an electric distribution system; an importer or exporter; the owner of an industrial system; a direct access customer or the purchaser of a PPA in accordance with Part ~~4.~~16 of the Act.

"Emergency" means, as declared by the System Controller, either: any abnormal system condition which requires immediate manual or automatic action to prevent abnormal system frequency deviation, abnormal voltage levels, equipment damage, or tripping of system elements which might result in cascading effects; or a state in which the AIES lacks sufficient System Support Services.

"Energy Transfer" shall mean the quantity of energy transfer attributable to a transaction for service under Rate Schedule Export Service or Rate Schedule Import Service, based on the capacity at a Point of Interconnection and allocated to a Customer.

"Export Service" means service under Rate Schedule Export Service.

"Force Majeure" means: acts of God; strikes; lockouts or other industrial disturbances; vandalism; wars; riots; epidemics; landslides; lightning; earthquakes; explosions; fires; storms; intervention of federal, provincial, or local government (or from any of their agencies or boards); the order or direction of any court; inability to obtain, interruption, suspension, curtailment or other diminution of, supply of materials, utilities, or services from any supplier (including, without limitation, TFOs, System Support Service Providers or the System Controller) and any other causes, whether of the kind herein enumerated or otherwise, not within the control of the ~~Transmission Administrator~~AESO and which by the exercise of due diligence the ~~Transmission Administrator~~AESO is unable to prevent or overcome.

"Generating Unit" shall have the meaning as ascribed to in the Act.

"Governor" or **"Governor System"** means automatic control equipment with speed droop characteristics to control Generating Unit speed and/or electric power output.

"Hourly Application Fee" means the actual ~~Transmission Administrator~~AESO's costs associated with processing a Customer's request for interconnection to the AIES plus 30 per cent.

"Import Service" means service under Rate Schedule Import Service.

"Interconnection Requirements" means the requirements contained in the *Technical Requirements for Connecting to the Alberta Interconnected Transmission Grid* in either *Part 1: Technical Requirements for Connecting Loads or Part 2: Technical Requirements for Connecting Generators to the Alberta Interconnected Electric System*, published on the ~~Transmission Administrator~~AESO's website, as may be amended from time to time in accordance with the provisions of Article 5 below.

"ISO" means the Independent System Operator, a corporation established under the Act and whose role, responsibilities and duties are more particularly described therein.

"Looped" refers to transmission facilities that increase the number of electrical paths between any two POCs other than the POC that serves the Customer for whom the facilities are being or have been constructed.

"Losses" means the energy that is lost through the process of transmitting electric energy.

"MCR" means Maximum Continuous Rating. MCR is the maximum net power output that can be sustained by a generator over a long period.

"Metered Demand" means the rate at which electric energy is delivered to a POD, or from a POS, expressed in kW or MW, averaged over a 15-minute, 1-minute or other interval as deemed necessary by the ~~Transmission Administrator~~AESO.

"Metered Energy" means the quantity of energy reflected by the relevant Metering Equipment as having been transferred in a particular period of time.

"Metering Equipment" means any current transformers, potential transformers, interconnecting wiring, meters, remote metering communication facilities and

records used by the owner of the Metering Equipment in connection with these Terms and Conditions to measure Metered Demand.

"Non-dispensated Metering Equipment" means Metering Equipment installed after May 31, 1998 which is not the subject of a waiver or dispensation by Industry Canada of requirements under the E&GI Act.

"Non-Recallable Customer" means a Customer taking System Access Service pursuant to Rate Schedule DTS or Rate Schedule STS.

"Off-Peak" means those periods of time which are not On-Peak.

"On-Peak" means the period of time from 8:00 hrs. to 21:00 hrs., inclusive, during any Business Day.

"Operating Reserves" means the capability above system demand available to the AIES within 10 minutes following a supply contingency, required to provide for system regulation and local area protection and to correct for or stabilize the system in the event of contingencies, load forecasting errors and forced outages to Generating Units. Operating Reserve includes any or all of the following in any combination at a given time:

(a) **"Regulating Reserve"**, being an amount of Spinning Reserve responsive to AGC, which is sufficient to provide normal regulating margin;

(b) **"Spinning Reserve"**, being the amount of reserve synchronized to the AIES, responding automatically through governor action to fluctuations in AIES frequency and capable of assuming load instantaneously;

(c) **"Non-spinning Reserve"**, being the amount of generation capable of being connected to the AIES and loaded within 10 minutes, or demand that can be reduced within 10 minutes;

(d) **"Contingency Reserve"**, being a combination of Spinning and Non-spinning Reserve and of sufficient quantity to reduce Area Control Error to zero within 10 minutes following the loss of supply capacity. At least 50% of the Contingency Reserve shall be Spinning Reserve, which will automatically respond to frequency deviation.

"Opportunity Capacity" means the incremental amount of transmission capacity which is available under a System Access Service Agreement for Demand Opportunity Service to provide capacity in addition to Contract Capacity for DTS.

"Opportunity Service" means System Access Service offered to any Customer who can establish to the ~~Transmission Administrator~~AESO's satisfaction that it would not take System Access Service pursuant to Rate Schedule DTS and with respect to which, therefore, the service requirement presents the opportunity for incremental revenue with which the ~~Transmission Administrator~~AESO can offset transmission costs.

"Opportunity Service Customers" means those Customers which meet the criteria for Opportunity Service, as defined.

"Physical Capacity" means the maximum amount of electric power which a transmission facility, as rated by a TFO, is able to transmit.

"POC" or **"Point of Connection"** means a point at which electric energy is transferred between the Customer's facility and the AIES. A Point of Connection may be a Point of Supply (POS), a Point of Delivery (POD), or both.

"POD" or **"Point of Delivery"** means the point at which electric energy is transferred from the AIES to a Customer's facilities.

"Point of Interconnection" means the point at which electrical energy is transferred from the AIES to a neighboring jurisdiction and where the electric energy so transferred is measured;

"Pool Price" shall have the meaning ascribed to that term in the Act, and when used in the context of a particular hour, shall mean the pool price for that hour;

"POS" or **"Point of Supply"** means the point which electric energy is transferred from a Customer's facilities to the AIES.

"Power Factor" means the ratio of Real Power to Apparent Power.

"PPA" or **"Power Purchase Arrangement"** means those instruments setting forth the rights and obligations of the parties in relation to operation of Regulated Generating Units and entitlements to electricity and System Support Services and approved by the AEUB under ~~Section 45.91~~ Part 6 of the Act.

"PPA Effective Date" means January 1, 2001 or such other date as the Power Purchase Arrangements become effective.

"PSS" means power system stabilizer.

"Radial" facilities are those transmission facilities that are not Looped.

"Ratchet Level" shall have the meaning ascribed thereto in Rate Schedule DTS.

"Rate Schedules" means the schedules attached to and forming part of the Tariff, which set out the respective rates to be charged, and credits to be attributed, for each type of System Access Service.

"Rated Capacity" means the maximum amount of electric power which a transmission facility is rated by the manufacturer to be able to transmit.

"Reactive Power" means the portion of electricity that establishes and sustains the electric and magnetic fields of alternating current equipment, usually expressed in kilovars ("kVAr") or megavars ("MVAr").

"Real Power" means the rate of producing, transferring, or using electrical energy, expressed in kilowatts ("kW") or megawatts ("MW").

"Regulated Generating Unit" shall have the meaning ascribed thereto in the Act;

"Representatives" means the directors, officers, employees, consultants and agents of the ~~TA~~AESO.

"RMS" means the Reliability Management System (and all mandatory operating criteria required thereby) adopted and enforced by the WSCC.

"Statutory Holiday" means New Years Day, Family Day, Good Friday, Victoria Day, Canada Day, Heritage Day, Labour Day, Thanksgiving Day, Remembrance Day, Christmas Day and Boxing Day.

"STS" or **"Supply Transmission Service"** means service under Rate Schedule Supply Transmission Service.

"STS Capacity" means the Contract Capacity as set out in the System Access Service Agreement for Supply Transmission Service.

"System Access Service" or **"service"** has the meaning ascribed to the term "system access service" in the Act;

"System Access Service Agreement" means that contract, entered into between the ~~Transmission Administrator~~ISO carrying on business as the AESO and a Customer, in one of the forms attached hereto as Appendix "B", which establishes the specific terms pursuant to which each individual Customer obtains System Access Service.

"System Controller" or **"SC"** shall have the meaning ascribed to that term in the Act.

"System Disturbance" means an unplanned event, which produces an abnormal AIES condition such as high or low frequency, abnormal voltage or oscillations in the AIES.

"System Security" means the ability of the AIES to withstand events such as electric short circuits, unanticipated loss of AIES components and switching operations without experiencing cascading loss of AIES components or uncontrolled loss of load.

"System Support Services" shall have the meaning ascribed to that term in the Act.

~~"TA" means the Transmission Administrator.~~

"Tariff" means these Terms and Conditions and Appendices attached hereto and the Rate Schedules as approved by the AEUB.

"TFO" means Transmission Facilities Owner.

"Transmission Administrator Operating Policies" or **"TAOPs"** means the standards and practices established by the ~~Transmission Administrator~~AESO to guide operation of the transmission system, as modified by the ~~Transmission Administrator~~AESO from time to time.

"Transmission Must-Run" means Constrained On dispatch of a Generating Unit to a specific level in accordance with a Dispatch Instruction to maintain System Security.

"UFS" or **"Under-frequency Load Shedding Credit"** means the under-frequency load shedding provisions as set forth in Rate Schedule Demand Under-Frequency Load Shedding and the credits therefor.

"Western Interconnection" means the area comprising those states and provinces, or portions thereof, in Western Canada, Northern Mexico and the Western United States in which members of the WSCC operate synchronously connected transmission systems.

"WSCC" means the Western Systems Coordinating Council and any successor organization.

ARTICLE 2
APPLICATION OF TARIFF

2.1 This Tariff sets forth the basic terms and conditions of service pursuant to which the ~~Transmission Administrator~~AESO will provide System Access Service to its Customers. This Tariff has been approved by the AEUB, defines service to be delivered by the ~~Transmission Administrator~~AESO and binds all of the ~~Transmission Administrator~~AESO's Customers. This Tariff defines the basic rights of the ~~Transmission Administrator~~AESO and all its Customers with respect to all services provided by the ~~Transmission Administrator~~AESO. By accepting service from the ~~Transmission Administrator~~AESO, a Customer is deemed to have accepted the terms and conditions and Rate Schedules contained in this Tariff. This Tariff becomes effective on the later of January 1, ~~2002~~2003 or the first day of the month after the AEUB approves it.

~~2.2~~ This Tariff shall continue in effect until replaced or amended pursuant to Section ~~54~~124 of the Act.

ARTICLE 3
USE OF TRANSMISSION SYSTEM

3.1 The ~~Transmission Administrator~~ AESO agrees to provide and make available System Access Service to all Customers who:

(a) satisfy the pre-contract conditions set out in Articles 5, 6 (and the definition of Opportunity Service Customers), 7, 10, 11, 12, and 21 and the applicable Rate Schedule(s);

(b) have executed a System Access Service Agreement; and

(c) continuously abide by these terms and conditions.

3.2 The ~~Transmission Administrator~~AESO reserves the right to withhold, limit or discontinue System Access Service under the following provisions:

(a) Article 4, System Support Services

(b) Article 5, Interconnection Requirements

(c) Article 10, Credit, Statement of Account and Payment Terms;

(d) Article 11, Provision of Information By Customers;

(e) Article 12, Metering;

(f) Article 13, Service Interruptions and Force Majeure;

(g) Article 15, Increases, Reductions or Termination of Contract Capacity; and

(h) the Rate Schedules, where appropriate.

In the event of a written request from a Customer, the ~~Transmission Administrator~~AESO shall provide a written explanation for its withholding System Access Service.

3.3 All Customers shall comply with the Interconnection Requirements. Failure to comply with Interconnection Requirements shall provide the ~~Transmission Administrator~~AESO with the right, at its sole discretion, to withhold or discontinue System Access Service.

3.4 The ~~Transmission Administrator~~ AESO provides System Access Service to Customers up to and including the POD or POS. All facilities interconnecting with the AIES on the Customer's side of the POD or POS ("Customer Facilities") are the responsibility of the Customer. This Tariff applies only to System Access Service supplied through facilities up to or from, and including, the POD or POS. The Customer must supply all Customer Facilities and the ~~Transmission Administrator~~AESO has no responsibility in respect of service provided over Customer Facilities.

3.5 No Customer or any other person may rearrange, disconnect, remove, interconnect with, or otherwise interfere with any transmission facility without the ~~Transmission Administrator~~AESO's prior written consent.

ARTICLE 4
~~SYSTEM SUPPORT SERVICES~~

UNDER-FREQUENCY LOAD SHEDDING

4.3 From and after the effective date of the Tariff, certain Customers may be eligible and required to provide under-frequency load shedding. The provisions with respect to those requirements, and the credits therefore, are set out in Rate Schedule Under-Frequency Load Shedding ("UFS").

4.4 Failure by any Customer to whom UFS applies~~,~~ to comply with the requirements thereof ~~shall provide the Transmission Administrator with the right~~ may cause the AESO to, at its sole discretion, ~~to~~ withhold, limit or discontinue System Access Service to such Customer. Nothing in this paragraph shall, however, affect or derogate from the right of the WSCC to levy penalties or the obligation of the Customer, if any, to pay such penalties as a result of failure to provide ~~System Support Services~~Under-Frequency Load Shedding to the ~~Transmission Administrator~~AESO as contemplated herein.

~~4.3 During certain system conditions, and for the purposes of maintaining System Security, as may be identified by the Transmission Administrator or the System Controller in real-time, the System Controller may require a Customer, in particular a generator, to operate its generator for "Transmission Must-Run" purposes. This requirement is directed to those Customers that do not have a contract with the Transmission Administrator to provide "Transmission Must-Run" services. The Transmission Administrator will compensate the generator as follows:~~

~~**Payment** = (Customer Offer Price – Pool Price) x MW dispatch, for each hour that the service was requested, where:~~

~~MW dispatch **= dispatch in MW as requested by the System Controller or Transmission Administrator.**~~

~~**Customer Offer Price** = the current valid offer into the Power Pool spanning the hours requiring the Transmission Must-Run or, if no current valid offer exists, the average of the offers spanning the most recent complete daily Off-Peak or On-Peak period, as the case may be, that have been made to and accepted by the Power Pool as valid offers. Averages will be derived for both On-Peak and Off-Peak hours and applied to the calculation of Payment for those periods of time that the "Transmission Must-Run" service was used.~~

ARTICLE 5
INTERCONNECTION REQUIREMENTS

5.1 Any Customer proposing to take, or is taking, System Access Service through a POD or POS must comply with the Interconnection Requirements.

5.2 Any Customer whose facilities include a synchronous Generating Unit which is operated in parallel to the electric system, whether connected at a transmission voltage or a distribution voltage, must have a PSS in service when the Generating Unit is operating and an AVR that is operated in a voltage control mode for all hours in which the Generating Unit is operating. The Customer shall not operate the Generating Unit unless the PSS and AVR are operating as required. The Customer shall report to the ~~Transmission Administrator~~AESO on a monthly basis, no later than the 5th Business Day of the month following the month to which the report relates, the PSS and AVR in-service periods for the preceding month. In the event that the ~~Transmission Administrator~~AESO becomes aware of a failure to comply with this requirement, the ~~Transmission Administrator~~AESO shall report the non-compliance to the WSCC and any penalties assessed by the WSCC as the result of the noncompliance shall be borne by the relevant Customer. Article 5.2 shall not apply to synchronous Generating Units 10 MVA and smaller that are connected at the distribution voltage until such time that the aggregate MVA output from such 10 MVA and smaller synchronous Generating Units connected at a distribution voltage in the Alberta Control Area exceeds 200 MVA.

5.3 Failure to comply with the Interconnection Requirements shall result in the ~~Transmission Administrator~~AESO withholding, suspending or terminating System Access Service, however the ~~Transmission Administrator~~AESO may, in its sole discretion, waive compliance with the Interconnection Requirements or the requirements of Paragraph 5.2 in respect of any existing Customer for whom, in the ~~Transmission Administrator~~AESO's reasonable opinion, the imposition thereof would create severe hardship or unnecessary costs.

5.4 The ~~Transmission Administrator~~AESO shall maintain the reliability of the AIES and the Western Interconnection in accordance with the RMS. The ~~Transmission Administrator~~AESO may amend the Interconnection Requirements in order to reflect, and to adhere to, changes to the RMS from time to time, upon further approval by the AEUB.

5.5 Article 5.2 does not apply to generators in existence as of June 1, 2000 that do not have a suitable excitation system unless the ~~Transmission Administrator~~AESO indicates otherwise. If the ~~Transmission Administrator~~AESO requires PSS or AVR to be added to a currently regulated generator in the future, the ~~Transmission Administrator~~ AESO will pay any costs prudently incurred in the installation of the PSS or AVR and will recover prudently incurred costs from tariff(s) approved by the AEUB. Any costs incurred by the currently regulated

generators in the installation of the PSS or AVR that are found by the AEUB to be imprudent in any ~~TA~~AESO tariff proceeding will be reimbursed to the ~~Transmission Administrator~~AESO by the party receiving the payment.

5.6 If the excitation system of an existing regulated or unregulated generator to which Article 5.2 does not apply is rebuilt or replaced, the new excitation system must be suitable for PSS, and a PSS/AVR must be installed.

ARTICLE 6
OPPORTUNITY SERVICE

6.1 To qualify for Opportunity Service the Customer shall submit a pre-qualification application to the ~~TA~~AESO. The Customer must also meet the specified eligibility criteria and must demonstrate that the intended use of the service would not proceed any other applicable rate. The Customer will pay a non-refundable $5,000 fee to the ~~Transmission Administrator~~AESO to evaluate the commercial eligibility of the Customer's DOS pre-qualification application. See Appendix B for a copy of the appropriate DOS proformas.

6.2 An Opportunity Service Customer shall only consume Opportunity Service for Metered Energy above its Contract Capacity. Opportunity Service Customers shall take System Access Service for all Billing Capacity equal to or below the Contract Capacity pursuant to Rate Schedule DTS.

6.3 In the event that the Metered Energy in a Billing Period for an Opportunity Service Customer is taken at a rate above the aggregate of the Opportunity Capacities under all such Customer's Opportunity Service System Access Service Agreements:

(a) The Metered Energy transfer at a rate above the said aggregate of Opportunity Capacities shall be added to the Metered Energy for the purpose of calculating the Customer's charges for that Billing Period under Rate Schedule DTS; and

(b) In the event that an Opportunity Service Customer has a Contract Capacity of zero and has not executed a System Access Agreement for DTS services, such Customer shall be deemed to have executed such an agreement, effective the beginning of the relevant Billing Period for which the aggregate of Opportunity Capacities was exceeded, for the purposes of determining a Billing Capacity, and for the purposes of applying the charges referred to in paragraph (a) above.

6.4 Opportunity Service is recallable:

(a) in accordance with the Rate Schedules;

(b) in accordance with the provisions of Article 13 below;

(c) whenever sufficient transmission system capacity becomes temporarily or permanently unavailable; and

6.5 From time to time, the ~~Transmission Administrator~~AESO may audit any Customer's eligibility for Opportunity Service. If, as a result of its audit, the ~~Transmission Administrator~~AESO finds that the Customer is or has been serving loads which do not, or no longer, qualify for Opportunity Service, the

~~Transmission Administrator~~AESO will change the Rate Schedule pursuant to which the Customer is billed. The ~~Transmission Administrator~~AESO may, in its sole discretion, recover retroactive amounts equal to the payments the Customer would have had to make if it had been taking System Access Service as a Non-Recallable Customer for the periods during which such Customer did not qualify for Opportunity Service. In the event the ~~Transmission Administrator~~AESO determines that the Customer is no longer qualified for Opportunity Service and prior to executing an agreement for Non Recallable Service, the Customer will be deemed to have executed such agreement, with the effective date of such agreement to be the effective date of disqualification.

6.6 Opportunity Service contracts will be offered under the following conditions:

(a) Commencement of the initial application for opportunity service must be requested at least 30 days prior to taking opportunity service;

(b) The applicant must have been determined, in the sole opinion of the ~~TA~~AESO to have met the commercial eligibility criteria for Opportunity Service and in particular the use of the Opportunity Service would not proceed on any other applicable rate;

(c) subsequent applications for opportunity service with the same parameters as the initial qualification application must be requested at least one hour prior to taking opportunity service;

(d) the minimum term of an opportunity service shall be a continuous eight hours from 00:00 hrs. midnight to 24:00 hrs., or such other minimum term as the ~~Transmission Administrator~~AESO may, in its discretion, set; and

(e) the maximum term of an opportunity service is one calendar month.

ARTICLE 7
INTERCONNECTION APPLICATION FEES

7.1 Effective January 1, 2002, the ~~Transmission Administrator~~AESO shall charge and the Customer shall pay a non-refundable interconnection application fee (the "Application Fee") to recover the ~~Transmission Administrator~~AESO's internal costs associated with a Customer's request for interconnection to the AIES. These costs may include, but are not limited to, the costs of estimating, engineering, customer service, project management, contracting and administration. The ~~Transmission Administrator~~AESO will not process the Customer's application, conduct the analysis or provide the detailed information to the Customer until the Customer has provided the ~~Transmission Administrator~~AESO with:

(a) a completed system access application form (copies of the Stage 1 and Stage 2 application forms can be obtained from the ~~Transmission Administrator~~AESO's website); and

(b) subject to Paragraph 7.4, the Application Fee paid in full.

7.2 Subject to Paragraph 7.4, the Application Fee charged is broken down into two stages and the stages are further broken down depending on the size of the Customer's proposed project:

(a) Stage 1 fees cover the ~~Transmission Administrator~~AESO's costs to provide the Customer:

(i) a draft functional specification;

(ii) in the case of a Customer which is a generator, a preliminary loss factor calculation; and

(iii) a cost estimate of the work specified in the draft functional specification;

(b) Stage 2 fees cover the ~~Transmission Administrator~~AESO's costs to provide the Customer:

i) an energization certificate.

ii) application by the TFO for transmission facilities;

iii) supporting letter from the ~~Transmission Administrator~~AESO to the Board on the facility application by the TFO; and

iv) provision of a System Access Agreement.

7.3 The Stage 1 and Stage 2 Application Fees are as follows:

Project Size	Stage 1 Fee	Stage 2 Fee
< 10 MW	$5,000	$5,000
> 10MW≤ 15 MW	$8,000	$8,000
> 15 MW ≤ 25 MW	$15,000	$15,000
> 25 MW	$40,000	$50,000

7.4 At the start of Stage 1 or Stage 2 the Customer, at its sole discretion, may elect to pay the actual ~~Transmission Administrator~~AESO costs associated with interconnection plus thirty percent (the "Hourly Application Fee") instead of the Stage 1 or Stage 2 Application Fees.

If the Customer elects to pay the Hourly Application Fee, the Customer will provide the ~~Transmission Administrator~~AESO with a deposit equal to the applicable Stage 1 or Stage 2 Application Fee. At the completion of the stage of the project the ~~Transmission Administrator~~AESO will provide the Customer with a detailed invoice of the work. If the deposit exceeds the amount of the invoice, the ~~Transmission Administrator~~AESO will refund the excess funds to the Customer. If the amount of the invoice exceeds the deposit the Customer shall pay the ~~Transmission Administrator~~AESO the amount owing.

7.5 Within five (5) business days of receiving a system access service application form and full payment of the Application Fee, the ~~Transmission Administrator~~AESO will review the system access service application to determine if it is complete and contains all the necessary information.

7.6 If the system access service application is complete the ~~Transmission Administrator~~AESO will notify the Customer, in writing, that the system access service application is complete (the "Confirmation Notice").

7.7 If the system access service application is not complete or the Application Fee has not been paid in full, the ~~Transmission Administrator~~AESO will notify the Customer, in writing, of the deficiencies (the "Deficiency Notice") and the application will not be processed.

7.8 A Customer or potential Customer may request the ~~Transmission Administrator~~AESO provide a preliminary loss factor calculation (only), in which case the Customer shall provide a completed loss factor calculation application form (copies of which can be obtained from the ~~Transmission Administrator~~AESO's web site) and pay a non-refundable fee of Twenty five hundred dollars ($2,500) to the ~~Transmission Administrator~~AESO.

7.9 For all other requests for service the Customer shall pay the ~~Transmission Administrator~~AESO's actual costs to prepare and provide the information, pursuant to the procedure set out in Paragraph 7.4.

7.10 Upon the ~~Transmission Administrator~~AESO providing the Customer with the documents and information set out in paragraph 7.2(a) at the completion of Stage 1, the Customer has sixty (60) days to notify the ~~Transmission Administrator~~AESO whether the Customer is proceeding to Stage 2, and , in the event it is proceeding, provide the ~~Transmission Administrator~~AESO with a completed Stage 2 application form. If the Customer elects not to proceed, does not notify or provide the ~~Transmission Administrator~~AESO with the Stage 2 application (along with Stage 2 Application Fee) within the 60 day period, the Customer's system access service application will be deemed to have been cancelled and the project shall be removed from the ~~Transmission Administrators~~AESOs' project list.

7.11 If a Customer's system access service application has been cancelled pursuant to paragraph 7.10, and the Customer subsequently wishes to reinstate its application the Customer must start the application process from the very beginning (i.e. submit a Stage 1 application and Application Fees pursuant to paragraph 7.1).

7.12 All detailed studies shall be conducted by the ~~Transmission Administrator~~AESO in the order in which the ~~Transmission Administrator~~AESO receives payment therefor. In the interest of maintaining confidentiality of each and every Customer and potential Customer, the ~~Transmission Administrator~~AESO shall conduct all detailed studies only on the basis of available information about actual and planned AIES facilities. For planning purposes, only those facilities with respect to which a Construction Commitment Agreement has already been executed shall be deemed "planned facilities". The ~~Transmission Administrator~~AESO shall not be liable to any Customer or potential Customer for any changes to the actual or planned facilities which occur between the date upon which the ~~Transmission Administrator~~AESO issues the detailed study and the date upon which the Customer executes a Construction Commitment Agreement.

7.13 All applications made by customers under previous Tariffs will continue to be offered service in accordance with those Tariffs. Stage 1 and Stage 2 fees will not be assessed to applications made prior to January 1, 2002. Any application made prior to January 1, 2002, which does not reach the end of Stage 1 by December 1, 2002, will be terminated.

ARTICLE 8
SECURITY FOR NEW TRANSMISSION FACILITIES

8.1 The ~~Transmission Administrator~~AESO is not obliged to arrange for commencement of the construction of new facilities required to initially facilitate System Access Service, or to accommodate increased Contract Capacity or Opportunity Capacity, for any Customer until that Customer has executed a Construction Commitment Agreement and, if required by the ~~Transmission Administrator~~AESO, has provided to the ~~Transmission Administrator~~AESO a performance bond, parental guarantee, irrevocable letter of credit or other security ("the security") in an amount adequate to fund cancellation costs as referenced in Paragraph 8.2 or the ~~Transmission Administrator~~AESO's reasonable estimate thereof, (or any portion thereof deemed appropriate), up to, in the aggregate, a maximum of the estimated costs of construction. The security shall be satisfactory to the ~~Transmission Administrator~~AESO in form and substance and the Construction Commitment Agreement shall be substantially in the form of the agreement attached hereto as Appendix "C".

8.2 In the event that, after a Construction Commitment Agreement is executed, the System Access Service and new transmission facilities are no longer required for any reason, the Customer shall pay all costs incurred in the procurement and construction of facilities to the date at which construction is ceased, plus all cancellation costs, penalties or other claims accrued due to the cessation and costs required for material salvage and reclamation of the construction site.

8.3 The Customer for whom new transmission facilities were built must execute a System Access Service Agreement prior to Commissioning of the new facilities. System Access Service shall be provided on a temporary basis for Commissioning at the Rate Schedule named in the System Access Service Agreement, however, during Commissioning (only), the Metered Demand may, at the sole discretion of the ~~Transmission Administrator~~AESO, be disregarded in calculating the Ratchet Level for service under Rate Schedule DTS.

ARTICLE 9
CUSTOMER CONTRIBUTION POLICY

9.1 In considering requests to provide service to a new POC, or to increase the capacity of, or improve the service to an existing POC, the ~~Transmission Administrator~~AESO will determine the appropriate means of delivering the requested service.

(a) If the ~~Transmission Administrator~~AESO determines that the most economic option for providing service to a Customer is a facility other than a transmission facility (such as a distribution-level extension or isolated generation), or that the Customer's request primarily represents a shift of supply or demand from an existing POC, then the full cost of the transmission upgrade or extension ("the project") shall be borne by the Customer.

(b) Otherwise, the Customer's contribution to project costs shall be determined in accordance with Article 9.2 through 9.4.

9.2 Project costs will be classified as either system-related costs or Customer-related costs, as follows:

(a) The costs of that part of the project associated with Looped transmission extensions shall be classified as system-related costs, and shall be paid by the ~~Transmission Administrator~~AESO.

(b) The costs of that part of the project associated with Radial transmission extensions shall be classified as system-related if it is proposed in the transmission development plan (as that plan exists on the date the project is Commissioned) that the extension become Looped within five years. The Customer shall pay the cost of advancing that part of the project from the date established in the transmission development plan, which cost shall be calculated as the difference between the present values of the capital costs of the advanced and as-planned projects using the discount rate as determined under Article 9.12.

(c) Where economics or system planning dictate that a facility larger than that required to serve the Customer is to be installed initially, then the cost of that portion of the project deemed to be in excess of the Customer's needs shall be classified as system-related. As the need to serve additional POCs arises, these system-related costs may be reclassified as Customer-related costs and allocated to the new Customers. The capacity between the Customer's requirements and the minimum size of facilities required to serve the Customer is not considered to be in excess of the Customer's requirements.

(d) All costs not identified under (a), (b), or (c) shall be classified as Customer-related costs. If the project is to serve a Customer not taking service under Rate DTS, then the Customer shall pay all Customer-related costs. Otherwise, the Customer's contribution to Customer-related costs shall be determined in accordance with Articles 9.3 and 9.4.

9.3 Customer-related costs will be classified as either supply-related costs or demand-related costs, as follows:

(a) The fraction of Customer-related costs classified as supply-related shall be STS/(STS+DTS), where STS and DTS are the STS and DTS Capacities, respectively, at the POC. All supply-related costs shall be paid by the Customer.

(b) The Customer-related costs not classified as supply-related costs shall be classified as demand-related costs. The Customer's contribution to demand-related costs shall be in accordance with Article 9.4.

9.4 The Customer's contribution to the demand-related costs shall be calculated as follows:

(a) *Customer contribution = demand-related costs – roll-in ceiling*, where:

(i) *roll-in ceiling = commitment term amount + revenue-related amount*;

(ii) *commitment term amount* = $400,000 for every one-year commitment term after the first five-year commitment term. A commitment term is a period within which the Customer commits to maintain its Contract Capacity at or above its initial Contract Capacity. The maximum commitment term amount is $6 million.

(iii) *revenue-related amount* = three times the levelized annual revenue from the new or expanded service, where the levelized revenue is determined based on the projected Contract Capacities that are contracted at the time of the calculation of the Customer contribution. The discount rate to be used in the calculation of the levelized annual revenue shall be that established under Article 9.12.

(b) If the calculation in (a) results in a negative Customer contribution, no Customer contribution is payable. The ~~Transmission Administrator~~AESO will make no payment to the Customer with respect to any excess of the roll-in ceiling over the demand-related costs.

9.5 Any Customer contribution to be paid to the ~~Transmission Administrator~~AESO must be paid prior to the ~~Transmission Administrator~~AESO initiating procurement of the required facilities, unless other credit arrangements acceptable to the ~~Transmission Administrator~~AESO are made. The discount rate to be used in any credit arrangement shall be that established under Article 9.12.

9.6 The cost estimate used in the calculation of project costs will be based on certain assumptions, including but not limited to assumptions about the method of construction, the routing of facilities, and the approvals and rights of way required to serve the Customer in accordance with the Customer's requests. In the sole opinion of the ~~Transmission Administrator~~AESO, where a request for service is changed by a Customer or any assumptions are changed for reasons beyond the reasonable control of the ~~Transmission Administrator~~AESO or the TFO, and a variance in the cost of the required facilities over the original estimate results, then:

(a) Subject to (b), where there is an increase in the Customer contribution, this amount is immediately payable to the ~~Transmission Administrator~~AESO, or

(b) If feasible, the Customer and the ~~Transmission Administrator~~AESO may modify the terms of the contract to adjust the Contract Capacity or the number of commitment terms.

(c) The Customer shall have the right to cancel the request for service by paying to the ~~Transmission Administrator~~AESO, and/or the TFO, all costs then incurred or required to be incurred to discharge the ~~Transmission Administrator~~AESO, and/or the TFO, of all obligations and to satisfactorily cancel the request for System Access Service.

9.7 Certain material events may result in a recalculation of the Customer contribution in respect of a project. Any recalculation shall make use of revised commitment terms, revenue-related amounts, and other available information, and may result in payments by the ~~Transmission Administrator~~AESO to the Customer or by the Customer to the ~~Transmission Administrator~~AESO. The circumstances giving rise to contribution adjustments include, but are not limited to, those in which:

(a) A Customer materially increases or decreases its Contract Capacity or number of commitment terms prior to the expiration of its original commitment terms;

(b) The actual Contract Capacities and/or incremental revenues turn out to be materially different, on a sustained basis, than originally projected;

(c) A facility that had been classified as system-related under Article 9.2(c) is reclassified as Customer-related due to load growth or the addition of a new POC.

(d) A material error is detected in the original calculation.

(e) A difference between the estimated costs of the project and the actual costs of the project.

9.8 If the ~~Transmission Administrator~~AESO installs facilities to serve a Customer that is required to pay a contribution, and then uses those facilities to serve other Customers within 20 years of their Commissioning, the ~~Transmission Administrator~~AESO will adjust the original Customer's contribution and assess each of the new Customers a contribution, as follows:

(a) The contributions of the existing Customer and the new Customers will be determined on the basis of:

(i) the commitment terms of the original and new Customers;

(ii) the revenue-related amounts of the original and new Customers;

(iii) the Contract Capacities of the original and new Customers;

(iv) the extent of shared facilities; and

(v) the time interval between the Commissioning of the original and new Customers.

(b) If the interval described in (a)(v) is not greater than five years, then the original Customer is eligible for the full amount of the adjustment. If the interval is greater than five years, then for the remaining 15 years the adjustment will be determined on a straight-line, declining-balance basis.

(c) Commencing in year 11, any project whose remaining adjustment is less than $50,000 shall be deemed to have an adjustment balance of zero, and no further refunds shall be due.

(d) An adjustment as described above will also apply to situations in which the ~~Transmission Administrator~~AESO subsequently deems that all or part of an original Customer's facilities have become system-related.

9.9 Where relocation of transmission facilities is required, the ~~Transmission Administrator~~AESO will ensure that all reasonable costs in relocating any transmission facilities are paid for by the Customer.

9.10 Where new facilities between adjacent Control Areas are required, the cost of such facilities will be shared equally between the ~~Transmission Administrator~~AESO and the party responsible for costs in the other Control Area.

9.11 The ~~Transmission Administrator~~AESO reserves the right to exercise its discretion, acting reasonably, in the application of the contribution policy. Without limiting the generality of this discretion, the ~~Transmission Administrator~~AESO may:

(a) Limit the maximum number of commitment terms used to determine the roll-in ceiling.

(b) Determine costs to be system-related in certain circumstances that might, under strict application of the foregoing, have been classified as customer-related.

(c) Determine that a refund of a Customer contribution may not be given or that a refund may be deferred pending the attainment of certain specified conditions. Upon attainment of the specified conditions, the Customer may be eligible for a full or partial refund.

(d) Determine that a refund of a Customer contribution must be returned to the ~~Transmission Administrator~~AESO where it is demonstrated that an error was made or that an inappropriate refund was given.

9.12 The discount rate applicable to payments due under this Article shall be determined as follows:

(a) For unassigned transmission facilities, for transmission facilities supplied to the ~~TA~~AESO by an investor owned Transmission Facility Owner or for facilities supplied to the ~~TA~~AESO by an income tax paying municipally owned Transmission facility Owner:

.65(GCB + 1%) + .35(GCB + 3.5%)/(1 - T)

where GCB is equal to the yield on 30-year Government of Canada bonds and T is equal to combined federal and provincial income tax rate for investor owned TFOs.

(b) For transmission facilities supplied to the ~~TA~~AESO by a non income tax paying municipally owned Transmission Facility Owners:

the yield on 30-year Government of Canada bonds plus 1.9 percent.

ARTICLE 10
CREDIT, STATEMENT OF ACCOUNT AND PAYMENT TERMS

10.1 After Commissioning, the ~~Transmission Administrator~~AESO will issue a Statement of Account for System Access Service to each Customer no later than fifteen (15) Business Days after the end of each Billing Period. The ~~Transmission Administrator~~AESO will determine the payment required and funds owed by each Customer for System Access Service at each POD and POS, as applicable, using available Metered Demand, Metered Energy or Energy Transfer data, as applicable, to calculate charges and any applicable credits. The ~~Transmission Administrator~~AESO may deduct amounts owing by the ~~Transmission Administrator~~AESO to the Customer or its Affiliates under other agreements between the ~~Transmission Administrator~~AESO and the Customer or its Affiliates from the Statement of Accounts.

10.2 All Customers requiring access to the AIES must execute a System Access Service Agreement with the ~~Transmission Administrator~~AESO for each POD and POS.

10.3 A Customer obtaining System Access Service may be afforded credit by the ~~Transmission Administrator~~AESO. The Customer shall provide the ~~Transmission Administrator~~AESO with any financial information that the ~~Transmission Administrator~~AESO reasonably requests prior to the ~~Transmission Administrator~~AESO granting service in order that the ~~Transmission Administrator~~AESO may establish the Customer's ability to pay and/or creditworthiness.

10.4 The ~~Transmission Administrator~~AESO may request, at any time a deposit of up to three months' payment in advance for System Access Service, based on the ~~Transmission Administrator~~AESO's estimate of the appropriate sum based on the Customer's historic usage.

10.5 If the Customer fails to provide adequate security or advance payment to the ~~Transmission Administrator~~AESO within ten (10) days of the ~~Transmission Administrator~~AESO's request, the ~~Transmission Administrator~~AESO may immediately withhold or suspend the Customer's System Access Service. However any such withholding or suspension shall not relieve the Customer from any obligation to pay any rate, charge or other amount payable which has accrued or is accruing to the ~~Transmission Administrator~~AESO.

10.6 The ~~Transmission Administrator~~AESO may use estimated values to produce a Statement of Account when Metered Demand data is not available or is incomplete, when Metering Equipment fails, or when the data is under Dispute. The ~~Transmission Administrator~~AESO may also use estimated values to produce a Statement of Account if the ~~Transmission Administrator~~AESO's billing and settlement system is unable to produce a Statement of Account. In the event

that a Statement of Account is based on estimated values, an adjustment will be made on a subsequent Statement of Account to reflect the use of actual or more appropriate estimated values and the ~~Transmission Administrator~~AESO may increase or reduce the amount billed in a subsequent Statement of Account in order to correct any underpayment or overpayment.

10.7 Effective January 1, 2002, where a Customer is an industrial site where multiple POCs are required, the ~~Transmission Administrator~~AESO may totalize the POCs and produce one Statement of Account for the Customer. The ~~Transmission Administrator~~AESO will base its decision to totalize on a review of the economics of providing more than one POC, reclassification of the site as an AEUB designated industrial system, or the existence of a credible transmission bypass alternative.

10.8 The Customer shall pay the entire amount reflected as owing by it on the Statement of Account, notwithstanding any unresolved Dispute between the ~~Transmission Administrator~~AESO and the Customer, no later than the twentieth Business Day after the end of the Billing Period. Payment shall be made by way of electronic funds transfer to the bank account specified by the ~~Transmission Administrator~~AESO.

10.9 Late payments by the Customer shall be subject to a late payment charge of 1.5% per month for each month or part thereof for which such payment is late. The ~~Transmission Administrator~~AESO will also assess the defaulting Customer for all administrative and collection costs relating to the recovery by the ~~Transmission Administrator~~AESO of amounts owed. The ~~Transmission Administrator~~AESO may suspend System Access Service and realize upon any security provided by the defaulting Customer if the Customer is in arrears by more than one month. System Access Service to the Customer shall not thereafter be re-instated until the Customer has paid all amounts owing to the ~~Transmission Administrator~~AESO in full and has restored or secured its credit facility in a manner satisfactory to the ~~Transmission Administrator~~AESO.

ARTICLE 11
PROVISION OF INFORMATION BY CUSTOMERS

11.1 Customers shall provide the following information necessary to enable the ~~Transmission Administrator~~AESO to provide and maintain System Access Service that is safe, adequate and proper. When the required information has an impact on safety or system security, failure to provide the required information will result in suspension, termination or delay of System Access Service. System Access Service will not thereafter be reinstated, terminated or modified (as the case may be) until the necessary information is provided to the ~~Transmission Administrator~~AESO. When the required information does not have an impact on safety or system security, failure to provide the required information will result in the ~~Transmission Administrator~~AESO making application for approval of an information sharing arrangement pursuant to the Act and seeking to recover 100% of the actual costs of pursuit of its application from the Customer whose actions necessitated the application.

11.2 In addition to payment of the Application Fee (provided for in Article 7 above), information is required prior to providing a detailed cost quotation for new System Access Service. Detailed information is required to assess the impact of new demand or generation on the system, to determine whether new transmission facilities will be required in order to accommodate the new load or generation, and to produce functional specifications necessary to procure any new transmission facilities.

11.3 A Demand Customer shall provide a detailed request for System Access Service to accommodate a new or increased demand, which must include information regarding the retail customer's identity, the location, peak expected operating demand, desired in-service date and a forecast of future demand.

11.4 A Supply Customer who is requiring service for new generation or increase in capacity at an existing generation plant must submit a detailed request for System Access Service. The request must include information regarding the electrical characteristics of the generator so that the ~~Transmission Administrator~~AESO can complete a detailed analysis of impact on the system and produce a detailed cost quotation.

11.5 The appropriate forms for making a detailed request for System Access Service are published on the ~~Transmission Administrator~~AESO's website.

11.6 Additional technical information shall be required during construction and prior to energization of new interconnections or increases of capacity at existing PODs and/or Commissioning at POSs so that the ~~Transmission Administrator~~AESO may ensure the ongoing security of the existing electrical system. Technical information is required prior to energization of load, as requested by the ~~Transmission Administrator~~AESO, regarding the new transmission facilities

including, but not limited to, transformer and line information. Technical information is required prior to Commissioning of new generation, as requested by the ~~Transmission Administrator~~AESO, including, but not limited to, data regarding the electrical characteristics of the generator and unit transformer. The appropriate forms for fulfilling pre-commissioning information requirements are published on the ~~Transmission Administrator~~AESO's website.

11.7 Additional information may be required prior to Commissioning and Commercial Operation. Commissioning shall not occur until the Customer has received written approval thereof from the ~~Transmission Administrator~~AESO.

11.8 The ~~Transmission Administrator~~AESO requires forecast information and updated information from all Customers to plan, operate and optimize the AIES. On October 1st of each calendar year and whenever new information arises, all Customers shall provide the ~~Transmission Administrator~~AESO with a copy of the Customer's operating procedures and a schedule of planned or maintenance outages for the two subsequent calendar years. On October 1st of each calendar year and whenever new information arises, all Customers shall provide the ~~Transmission Administrator~~AESO with forecast information for the subsequent five (5) years, including:

(a) Forecast Maximum Contract Capacity by POD or POS by month,

(b) Location and size of any new POD and POS required,

(c) Name and location of existing POD and POS which may no longer be required.

The appropriate forms for provision of forecast and update information are published on the ~~Transmission Administrator~~AESO's website.

11.9 The ~~Transmission Administrator~~AESO requires detailed information regarding Metering Equipment information. The Customer shall provide the ~~Transmission Administrator~~AESO with the Metering Equipment information outlined in Appendix "D".

11.10 The Customer shall provide to the ~~Transmission Administrator~~AESO, upon request, any information that the ~~Transmission Administrator~~AESO requires in order to discharge its duties and functions under the Act and for compliance with any external agency's reporting requirements.

~~11.11 If the Customer is the Buyer of a PPA, it shall provide written confirmation to the Transmission Administrator that it has entered into an agreement with the owner of the underlying Regulated Generating Unit (the "Owner") whereby the Customer shall:~~

~~(a) temporarily assign its System Access Service Agreement(s) to the Owner for the duration of the events described in Article 14 (Force Majeure)and Article 15 (Destruction of Unit) of the PPA; and~~

~~(b) permanently assign its System Access Service Agreement to the Owner if the Buyer of the PPA has terminated the PPA in accordance with Article 14 (Force Majeure), Article 15 (Destruction of Unit) or Article 16 (Default and Termination) of the PPA.~~

11.11 ~~11.12~~ The ~~Transmission Administrator~~AESO is not responsible for any delay, interruption, damage or other problems caused by a delay in the provision of information required from a Customer under the provisions of this Article 11.

ARTICLE 12
METERING

12.1 The selection, use and calibration of Metering Equipment shall be accomplished in accordance with the E&GI Act, except where the ~~Transmission Administrator~~AESO requires revenue meters to be accurate to within 0.5% for loads up to 10 MVA and 0.2% for loads above 10 MVA (the "System Accuracy Standard").

12.2 The Customer may arrange to have any Non-dispensated Metering Equipment tested and/or calibrated to the System Accuracy Standard. If the Customer requests a test and the meter is subsequently found to be accurate within the System Accuracy Standard, then the Customer shall pay for the cost of the testing and shall be invoiced for this cost in its next Statement of Accounts.

12.3 The ~~Transmission Administrator~~AESO may, at its discretion, require a Customer to install Metering Equipment on the Customer's premises, at the Customer's sole cost, and the Customer shall comply with such a request in a timely manner. If the Customer refuses or fails to comply with such a request, the ~~Transmission Administrator~~AESO may request, and the Customer shall grant, access at any reasonable time to the Customer's premises so the ~~Transmission Administrator~~AESO may enter the Customer's premises to install Metering Equipment, at the Customer's sole cost.

12.4 The ~~Transmission Administrator~~AESO may request, and the Customer shall grant, access at any reasonable time to the Customer's premises so the ~~Transmission Adminsitrator~~AESO may, at the Customer's sole cost, enter the Customer's premises to read any Metering Equipment installed on the Customer's premises.

12.5 The Customer may request, at the Customer's sole cost, that the ~~Transmission Administrator~~AESO arrange for testing of any Metering Equipment.

12.6 The ~~Transmission Administrator~~AESO may require testing of Metering Equipment at any time. In the event that the Metering Equipment meets the System Accuracy Standard, the ~~Transmission Administrator~~AESO shall bear the cost of such testing. In the event that the Metering Equipment does not meet the System Accuracy Standard, the Customer shall bear the costs of such testing and the required recalibration.

12.7 If a Dispute should arise with respect to the Metering Equipment or Metering Equipment data, the Dispute shall be resolved in accordance with the provisions of Article 16 below.

12.8 Metering signals in the form of energy pulses, reactive energy pulses, analog values of energy and reactive energy can be provided to the Customer, upon

written request and at the Customer's cost. This cost shall be included in the Customer's Statement of Accounts.

12.9 All Customers shall provide Metering Equipment that measures Metered Demand in fifteen (15) minute intervals. The ~~Transmission Administrator~~AESO may, at its discretion, require a Customer to provide Metering Equipment that is capable of measuring Metered Demand at one (1) minute intervals or at such other intervals as may be determined by the ~~Transmission Administrator~~AESO.

12.10 The Customer shall make reasonable efforts to provide the ~~Transmission Administrator~~AESO, in accordance with the E&GI Act and the TAOPS, the following data:

(a) fifteen (15) minute interval POC metering data; or

(b) if requested by the ~~Transmission Administrator~~AESO, one (1) minute interval POC metering data.

The Customer shall provide the metering data set out above, for the previous day, by 12:00 p.m. of the next business day. Revenue class meters will be used for billing purposes, energy purchases and sales and system support service purchases.

12.11 Subject to Paragraph 12.12, failure to comply with the metering requirements set out in this Article 12 shall result in the ~~Transmission Administrator~~AESO withholding, suspending or terminating System Access Service.

12.12 The ~~Transmission Administrator~~AESO shall not withhold, suspend or terminate System Access Service under paragraph 12.11 unless and until the metering non-compliance has been resolved in accordance with the provisions of Article 16, the Customer has failed to adhere to the arbitrator's decision in a timely manner and the ~~Transmission Adminsitrator~~AESO has provided the Customer with five (5) days prior written notice of its intention to withhold, suspend or terminate System Access Service.

ARTICLE 13
SERVICE INTERRUPTIONS AND FORCE MAJEURE

13.1 Although precautions are taken to guard against System Access Service interruptions, the ~~Transmission Administrator~~AESO does not guarantee uninterrupted System Access Service. The ~~Transmission Administrator~~AESO is not responsible for interruptions which occur as a result of:

(a) scheduled or planned facility maintenance activities;

(b) construction, commissioning and facility testing activities;

(c) unscheduled or unplanned events (such as, but not limited to, emergency equipment maintenance and Emergencies);

(d) Force Majeure;

(e) breaches of obligations owed to the ~~Transmission Administrator~~AESO by its suppliers or Customers; or

(f) as otherwise expressly allowed by a Rate Schedule.

13.2 Whenever System Access Service has been interrupted, diminished or reduced for reasons other than a breach of these Terms and Conditions by the Customer, the ~~Transmission Administrator~~AESO shall make all reasonable efforts to ensure that service is restored as soon as practicable after the interruption, diminution or reduction.

13.3 The Customer's obligations to pay for System Access Service, to provide information and to maintain Interconnection Requirements shall not be affected during, or as the result of, any event of Force Majeure or other System Access Service interruption expressly contemplated under this Tariff.

ARTICLE 14
LIMITATION OF LIABILITY

14.1 Notwithstanding anything to the contrary contained in these Terms and Conditions, no action lies against the ~~Transmission Administrator~~AESO, the ISO, nor its affiliates, directors, officers or employees ("~~Transmission Administrator~~AESO Persons") and ~~Transmission Administrator~~AESO Persons are not liable for any act or omission carried out or purportedly carried out in accordance with this Tariff ("~~Transmission Administrator~~AESO Person Act") unless the ~~Transmission Administrator~~AESO Person Act constitutes willful misconduct, negligence, breaching of contract or if the ~~Transmission Administrator~~AESO Person Act is not carried out in good faith. If a ~~Transmission Administrator~~AESO Person is liable to another person for a ~~Transmission Administrator~~AESO Person Act, then the ~~Transmission Administrator~~AESO Person is liable for only Direct Loss or Damage suffered or incurred by that other person.

ARTICLE 15
INCREASES, REDUCTIONS OR TERMINATION OF CONTRACT CAPACITY

15.1 In the event that a Customer desires to increase the Contract Capacity in its System Access Service Agreement at an existing POD or POS, the Customer must execute an amended System Access Service Agreement. If new facilities or upgrades are required to provide the new service or to provide the amended service level, the requirements for a Customer Contribution shall apply and the provisions of Article 8 shall be applicable.

15.2 The Contract Capacity for a new POS established by the ~~Transmission Administrator~~AESO shall not exceed the sum of the MCR of all generators connected to the AIES by the new POS less the sum of all gross loads that offset the energy delivered to the AIES from that POS under normal operating conditions.

15.3 (a) Subject to paragraphs (b) and (c), the Metered Demand for a Customer taking service under Rate Schedule DTS or Rate Schedule STS shall not exceed the lesser of:

(i) 110% of the Contract Capacity;

(ii) the Rated Capacity of any transmission facilities comprising its interconnection; or

(iii) the Physical Capacity of any transmission facilities comprising it's interconnection.

In the event that the foregoing is not complied with, the ~~Transmission Administrator~~AESO shall have the right to discontinue the applicable System Access Service until the Customer installs equipment to limit its Metered Demand.

(b) A DTS Customer may temporarily exceed the level stipulated in subparagraph 15.3(a)(i) to the extent it has in place a System Access Service Agreement for an Opportunity Service at the applicable POD.

(c) Subject to subparagraph 15.3(d) an STS customer may temporarily exceed the level stipulated in subparagraph 15.3(a)(i), with the ~~Transmission Administrator~~AESO's consent obtained on a minimum twenty-four (24) hours' notice, provided that the ~~Transmission Administrator~~AESO determines that the transmission system can safely accommodate the proposed energy without risk of disturbance to other ~~Transmission Administrator~~AESO customers.

(d) Under exceptional circumstances, the ~~Transmission Administrator~~AESO may allow a reduction to the notice provisions for STS customers with

frequently repeated transactions of similar size and duration, but under no circumstance will a notice period of less than one (1) hour be accepted.

15.4 At least once per year, the ~~Transmission Administrator~~AESO will review the Contract Capacity of STS customers. The ~~Transmission Administrator~~AESO may reduce a customer's STS Contract Capacity to:

(a) The mean metered power delivered to the AIES in the preceding twelve (12) months; or

(b) For low capacity factor generators, the mean metered power delivered to the AIES over recurrent periods that are shorter than twelve (12) months, as determined by the ~~Transmission Administrator~~AESO

if such deliveries are more than 10% below the existing Contract Capacity or as mutually agreed to between the Customer and the ~~Transmission Administrator~~AESO.

15.5 System Access Service Agreements between the ~~Transmission Administrator~~AESO and Customers who operate Regulated Generating Units shall be terminated on the PPA Effective Date, with the exception of Regulated Generating Units that are not sold at the PPA auction and the Regulated Hydro Generating Units ~~that are listed~~outlined in ~~Table "A" to~~ Appendix ~~"F"~~E.

15.6 System Access Service Agreements with an effective date after the PPA Effective Date between the ~~Transmission Administrator~~AESO and Customers who operate Regulated Generating Units or who have entered into a Power Purchase Arrangement with the owner of a Regulated Generating Unit shall terminate at the end of the base life year of the Regulated Generating Unit as outlined in ~~Part 1 of the Schedule attached to the Act~~ Appendix E with the exception of the following Regulated Generating Units listed below:

(a) Rossdale Units 8, 9 and 10's deemed base life year shall be 2003; and

(b) Rainbow Units 1, 2 and 3's deemed base life year shall be 2005;

15.7 Reductions of Contract Capacity at a POD or a POS will be made five (5) years after receipt of written notice from the Customer. The Contract Capacity immediately following the five (5) year notice period shall be the maximum of:

(a) the pre-notice Contract Capacity less the reduction of Contract Capacity requested by the Customer; or

(b) the highest Metered Demand during the notice period less the reduction of Contract Capacity requested by the Customer.

15.8 Separate written notice must be provided for increases or reductions of Contract Capacity at each respective POD and POS at a single transmission station; no net reductions will be accepted or effected.

ARTICLE 16
DISPUTE RESOLUTION

16.1 A Dispute shall be referred to a senior officer from each of the ~~Transmission Administrator~~AESO and the relevant Customer for resolution.

16.2 If the Dispute has not been resolved within thirty (30) days after referral to the senior officers, either the ~~Transmission Administrator~~AESO or the Customer may require, by written notice, that the Dispute be resolved through arbitration. The ~~Transmission Administrator~~AESO shall advise the AEUB of any matter going to arbitration within thirty (30) days of the matter being referred to arbitration. The parties shall appoint a mutually satisfactory arbitrator within ten (10) days of the notice to resolve the Dispute through arbitration. In the event that the parties cannot agree on a single arbitrator within ten (10) days, each party shall appoint an arbitrator within ten (10) days thereafter by written notice, and the two arbitrators shall together appoint a third arbitrator. In the event that a tribunal is required, the third arbitrator shall be appointed within twenty (20) days of written notice for arbitration. The arbitrator or tribunal shall render a decision within thirty (30) days of the last appointment. The ~~Transmission Administrator~~AESO shall advise the AEUB of the results of the arbitration within thirty (30) days of the Arbitrator's decision. The ~~Transmission Administrator~~AESO shall also furnish the AEUB with a list of parties potentially affected by the results of the arbitration. The arbitration shall be conducted in accordance with the Arbitration Act (Alberta), as amended from time to time. In the event of a conflict between these Terms and Conditions and the Arbitration Act, these Terms and Conditions shall prevail.

16.3 Any interested party adversely and unduly affected by the decision of an arbitrator or a tribunal is entitled to make an application to the AEUB requesting a clarification or change to these Terms and Conditions.

16.4 Pending resolution of any Dispute, the ~~Transmission Administrator~~AESO and the Customer shall continue to perform their respective obligations under this Tariff.

ARTICLE 17
MAINTENANCE OF RECORDS

17.1 The ~~Transmission Administrator~~AESO shall maintain records for a period of ten (10) years relating to those matters associated with the Tariff, such as capital costs of facilities, which require such level of data retention to perform necessary calculations or otherwise provide necessary information, and for any other matter, the ~~Transmission Administrator~~AESO shall maintain records for a period of six (6) years. Data required to verify any billing information provided by the ~~Transmission Administrator~~AESO may be made available to Customers during regular business hours and the Customer will be responsible to pay for all of the costs of retrieval and provision of the data.

ARTICLE 18
COSTS ASSOCIATED WITH REBILLING

18.1 When invoices to Customers have to be recalculated and reissued forty-five (45) days or more after end of the applicable billing period as a result of:

(i) unavailable or incomplete meter data, or

(ii) inaccurate estimates of meter data,

(iii) reconciliation with updated estimates of meter data,

the cost of recalculating and reissuing the affected Statement of Account shall be recovered from the Customer taking service from the relevant Metering Equipment. The ~~Transmission Administrator~~AESO shall charge $1,000 for each recalculated and reissued invoice.

ARTICLE 19
NOTIFICATIONS

19.1 All notices given or served upon the ~~Transmission Administrator~~AESO in accordance with this Tariff shall be in writing and shall be marked "Important" and given by personal service, telefax or by registered letter addressed to:

~~Transmission Administrator of Alberta~~AESO
Attention: Manager, Customer Service
900, 736 – 8 Ave SW
Calgary, Alberta, T2P 1H4

or by telefax addressed to:

~~Transmission Administrator of Alberta~~AESO
Attention: Manager, Customer Service
Fax (403) ~~705-5295~~266-2959

19.2 All notices given or served upon the Customer in accordance with this Tariff shall be in writing served by personal service, registered letter or telefax and sent to the address or addresses shown for such Customer in the relevant System Access Service Agreement.

ARTICLE 20
SPRDA GENERATORS

20.1 Generating Units constructed under the *Small Power Research and Development Act* (Alberta) ("SPRDA") are exempt from the provisions of Rate Schedule STS to the extent of the volume of energy sales which they conduct under contracts specifically executed pursuant to the provisions of the SPRDA.

ARTICLE 21
PEAK METERED DEMAND WAIVER

21.1 The ~~Transmission Administrator~~AESO may, in its sole discretion, waive the Metered Demand set in a Billing Period or any prior Billing Periods for the purposes of calculating the Billing Capacity when such level of Metered Demand was caused by one of the following:

(a) Commissioning as defined in the Article 1;

(b) activities required to repair and maintain transmission facilities;

(c) pre-scheduled activities required to repair and maintain distribution facilities;

(d) load restoration activities following an outage of transmission or distribution facilities or caused by an Emergency;

(e) an event of Force Majeure; or

(f) compliance with a dispatch instruction from the System Controller during an Emergency.

ARTICLE 22
TRANSMISSION SYSTEM EXPANSION

22.1 Except in exceptional circumstances, the following material new transmission facilities shall be competitively procured:

(a) facilities with a capital construction cost of $10 million dollars or more;

(b) facilities of a voltage of 240kV or higher; or

(c) interconnections with neighboring Control Areas.

22.2 The ~~Transmission Administrator~~AESO reserves the right to directly assign the construction of a new transmission facility in the event that the ~~Transmission Administrator~~AESO determines that the costs of administering a competitive procurement process would outweigh the benefits thereof.

22.3 Subject to Paragraphs 22.1 and 22.2, any Customer whose interconnection to the AIES requires the construction of material new transmission facilities, whose load or generation equals or exceeds 5 MW and who is transmission-interconnected, may elect to have the facilities competitively procured by the ~~Transmission Administrator~~AESO. Any Customer electing to have the ~~Transmission Administrator~~AESO competitively procure transmission facilities which do not meet one or more of the criteria listed in Paragraph 22.1 shall pay all reasonable out-of-pocket expenses (including, but not limited to, legal fees, technical consultants' fees and regulatory expenses) incurred by the ~~Transmission Administrator~~AESO while conducting the competitive procurement process. The ~~Transmission Administrator~~AESO shall be entitled to require the payment of deposits from time to time during the course of the competitive procurement process and the ~~Transmission Administrator~~AESO shall be entitled to withhold continuation of the process until such time as deposits are made.

22.4 In the event that a Customer requires facilities to be built in addition to those which the ~~Transmission Administrator~~AESO would otherwise provide ("Optional Facilities"), the Customer will be required to pay 100% of the cost of those additional facilities, however the Customer may choose to have those Optional Facilities competitively procured by the ~~Transmission Administrator~~AESO, subject to Paragraph 22.1 and in accordance with Paragraph 22.3.

22.5 The ~~Transmission Administrator~~AESO shall procure all transmission facilities. No Customer shall, without the prior written consent of the ~~Transmission Administrator~~AESO, directly procure transmission facilities, whether competitively or otherwise, except for transmission facilities directly assigned by the ~~Transmission Administrator~~AESO.

ARTICLE 23
MISCELLANEOUS

23.1 Each respective System Access Service Agreement executed by the ~~Transmission Administrator~~AESO hereunder shall be binding on any subsequent ~~Transmission Administrators~~ISO) for the length of its term.

23.2 A Customer can assign its System Access Service Agreement or any rights thereunder to another Customer who is qualified for the service available under such agreement, but only with the consent of the ~~Transmission Administrator~~AESO, such consent not to be unreasonably withheld.

23.3 In the event of any conflicts between the provisions of these Terms and Conditions, and the provisions of the Rate Schedules, the provisions of these Terms and Conditions shall govern.

23.4 Customers shall comply with dispatches and directives of the System Controller which are required for performance of Customers' obligations hereunder in real-time, including, without limitation, those related to Interconnection Requirements and provision of System Support Services.

ARTICLE 24

~~EMERGENCY PROVISION OF SYSTEM SUPPORT~~ANCILLARY SERVICES

24.5 During ~~an Emergency~~a state in which the AIES lacks sufficient Ancillary Services and for the purposes of maintaining system security, the System Controller may require a Customer to operate its ~~G~~generating ~~U~~unit to provide ~~System Support~~Ancillary Services. For the period during which the ~~Emergency~~conscription persists, Customers required to provide ~~System Support~~Ancillary Services shall be compensated as provided in ~~sections~~Article 24.2 or ~~24.3 (~~Article 24.3, whichever is applicable~~)~~.

24.6 If at the time ~~of~~ the ~~Emergency~~Customer is required to provide Ancillary Services the Customer has an existing contract with the ~~Transmission Administrator~~AESO, either directly or indirectly, to provide ~~System~~the ~~Support~~Ancillary Services in question (the "Existing Contract"), then the amount to be paid to the Customer by the ~~Transmission Administrator~~AESO for the ~~System Support~~Ancillary Services shall be determined according to the terms of the Existing Contract.

24.7 If at the time the Customer is required to provide an Ancillary Service and the Customer does not have an Existing Contract, then the amount to be paid to the Customer by the ~~Transmission Administrator~~AESO in respect of each ~~a~~Ancillary ~~s~~Service provided shall be the greater of:

(a) The sum, over all hours during which the Customer is required to provide the ~~System Support~~Ancillary Service pursuant to ~~section~~Article 24.1, of the product of the hourly MW dispatch and the highest price paid in the hour to Customers providing the ~~System Support~~Ancillary Service pursuant to Article 24.2; or

(b) The sum, over all hours during which the Customer is required to provide the ~~System Support~~Ancillary Service pursuant to ~~section~~Article 24.1, of the product of the hourly MW dispatch and 110% of the energy price in the hour as set by the Power Pool of Alberta, plus any additional charges from the Power Pool of Alberta (including but not limited to uplift charges) and charges from the ~~Transmission Administrator~~AESO net of pool energy receipts; or

(c) The direct costs incurred by the Customer to provide the required ~~System Support~~Ancillary Service, net of pool energy receipts, plus ten percent. Direct costs include, but are not limited to, ~~G~~generating ~~U~~unit start-up costs, costs to purchase replacement energy to fulfil Customers' contractual obligations, fuel costs and variable operation and maintenance costs; however, direct costs do not include indirect, incidental, consequential, or special damages arising out of or relating to the Customer providing ~~System Support~~Ancillary Services. Direct costs also include a prorate of fixed capacity costs and fixed maintenance costs applicable to the conscription period. The pro-rata share shall be calculated using the fraction of hours of providing ancillary services pursuant to Article 24.1 to the total operating hours of the service providing facility in the calendar month. For Customers with Power Purchase Arrangements that have annual start limitations and that are forced to make a start-up in response to a directive from the System Controller, the minimum pro-rata share of fixed costs shall be calculated as the total annual costs, times the number of starts consumed in providing ancillary services, divided by the annual start allowance. Revenues received by Customers, pursuant to the purchase of Power Purchase Arrangements, shall be treated as an offset to the prorate of fixed capacity costs; or

(d) The verifiable net opportunity cost incurred by the Customer to supply the required ~~System Support~~Ancillary Services taking into account all offsetting revenues from any source, such as pool energy receipts; or

~~(e) The sum, over all hours during which the Customer is required to provide the System Support Service pursuant to section 24.1, of the product of the hourly MW dispatch and the hourly difference between the Customer Offer~~Price and the Pool Price, ~~where Customer Offer Price is the current valid offer into the Power Pool or, if no current valid offer exists, the average of the offers spanning the most recent complete daily Off-Peak or On-Peak period, as the case may be, that have been made to and accepted by the Power Pool as valid offers.~~

24.8 For the purposes of this Article, MW dispatch means the amount of ~~a System Support~~an Ancillary Service (expressed in MW) that is provided by the Customer in response to a dispatch by the System Controller.

ARTICLE 25
CONFIDENTIALITY

25.1 The ~~Transmission Administrator~~AESO:

(a) shall not disclose the Confidential Information to any person except as permitted under this Tariff;

(b) shall only use or reproduce the Confidential Information for the purpose for which it was disclosed or another purpose contemplated in this Tariff;

(c) shall not permit unauthorized persons to have access to the Confidential Information; and

(d) shall only disclose the Confidential Information to those Representatives who need to know the information and have been informed of the confidential nature of the Confidential Information.

25.2 Exceptions to the confidentiality obligations stated in Paragraph 25.1 will be made when:

(a) the disclosure, use or reproduction of information if the relevant information is at the time generally and publicly available other than as a result of breach of confidence by the ~~Transmission Administrator~~AESO;

(b) the disclosure, use or reproduction of information with the consent of the person or persons who provided the relevant information;

(c) the disclosure, use or reproduction of information to the extent the Confidential Information:

(i) must be disclosed by law to any agent, government or governmental body, authority or agency having jurisdiction over the Transmission Authority;

(ii) must be disclosed to the Power Pool of Alberta or System Controller for the purposes of the Transmission Administration fulfilling its duties under the *EUA* (Alberta); and

(iii) must be disclosed to a TFO for the purposes of the ~~Transmission Administrator~~AESO fulfilling its duties under the *EUA* (Alberta). All information provided to a TFO shall

be subject to the confidentiality provisions in the TFO's Terms and Conditions of service.

the disclosure, use or reproduction of information if required in connection with legal proceedings, arbitration, expert determination or other dispute resolution mechanism relating to this Tariff;

(d) the disclosure of information if required to protect the safety of personnel or equipment, or to protect the reliability of the AIES; and

(e) the disclosure, use or reproduction of information as an unidentifiable component of an aggregate of information.

25.3 In the case of a request or demand for disclosure under Paragraph 25.2(c)(i) or Paragraph 25.2(d), the ~~Transmission Administrator~~AESO will provide notice to those affected by the request or demand as soon as reasonably practicable, so as to afford the opportunity to challenge such request or demand or seek injunctive relief or protection from the request or demand.

25.4 No provision of this Tariff obligates the Customer to treat its own information and agreements with the ~~Transmission Administrator~~AESO as confidential.

Appendix "A"

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Appendix "B"

System Access Service Agreement Proformas

SYSTEM ACCESS SERVICE AGREEMENT
DEMAND TRANSMISSION SERVICE

The following constitute the terms pursuant to which the ~~Transmission Administrator (TA~~Independent System Operator, **a corporation carrying on business under the trade name** Alberta Electric System Operator (AESO) , shall provide System Access Service to the Customer. (Defined terms used herein without definition shall have the meanings ascribed thereto in the Terms and Conditions of the ~~Transmission Administrator~~AESO's Tariff).

1. TYPE OF SERVICE

Service under this Agreement shall be provided pursuant to Rate Schedule Demand Transmission Service (DTS).

2. POINT OF INTERCONNECTION WITH THE TRANSMISSION SYSTEM

(a) Point of Supply (POD): The POD shall be [description, e.g. relative to Substation]

(b) Location:
Township_____ Range_____ W____M

3. CONTRACT CAPACITY

"x" MW

4. COMMISSIONING PERIOD FOR NEW FACILITIES, IF ANY:

5. EFFECTIVE DATE

_____ __, 2001

6. CUSTOMER CONTRIBUTION

The Customer Contribution charge is $_____.

Number of Commitment terms _____ x 5 equals _____ years.

7. RATES AND TERMS OF SERVICE

The supply of System Access Service pursuant to this Agreement, and the Customer's obligations with respect to connection and supply of System Support Services, shall be subject to the ~~Transmission Administrator~~AESO's Tariff, in particular to the Rate Schedule referenced under Paragraph 1.

8. NOTICES

Notices sent to the Customer pursuant to this Agreement shall be as follows:

Invoices:	Attention:	_____
	Address:	_____
		_____
		_____
	Fax:	_____
All other notices:	Attention:	_____
	Address:	_____
		_____
		_____
	Fax:	_____

9. [Optional Clause for Customer designated to provide under-frequency load shed]

_____MW of load is connected by an under-frequency load shed relay set to trip at ____Hz.

By executing in the space below, the Customer and the ~~Transmission Administrator~~AESO agree to the foregoing provisions.

~~**Transmission Administrator of Alberta**~~
Independent System Operator a corporation carrying on business under the trade name Alberta Electric System Operator

Per: _____ Date:
~~Name:~~ _____
~~Title:~~
Tony Demassi
Director, Customer Relations

Per: _____ Date: ____
Name: _____
Title: _____

_____
~~Customer~~

_____
~~Signature~~

Per: _____ Date: _____

Name: _____

Title:

DEMAND OPPORTUNITY SERVICE
STAGE 1 APPLICATION FOR OPPORTUNITY SERVICE

Stage 1 Application for Demand Opportunity Service (DOS)
Preliminary Assessment

The "Applicant", noted below, requests a preliminary assessment of the availability of Opportunity Service for the use described herein. The Applicant should be familiar with the information on Opportunity Service that appears on the ~~TA~~AESO's website, including the ~~TA~~AESO's Business Practices for Demand Opportunity Service and the ~~TA~~AESO's Term and Conditions of Service. This application does not bind the ~~TA~~ AESO or the Applicant to any contractual arrangement. There is no fee at Stage 1.

IDENTIFICATION OF END USER AND CUSTOMER

End User Name: _____

Customer Name: _____
(Must be an existing DTS Customer of the ~~TA~~AESO)

Primary Contact: Name: _____ Company: _____

(May be the end user or the Customer at Stage 1; however, the Stage 2 application must be made by the ~~TA~~AESO's Customer.)

Phone Number: _____ Fax number: _____ Email Address: _____

Facility Name: _____
Facility Location: LSD____**SEC**_____**TWP**_____**RGE**_____**MER**____
Connected AIES Substation (Name and Number): _____

Point of Delivery (POD): _____
(Description of the Point of Delivery)

TECHNICAL AND COMMERCIAL INFORMATION

The following preliminary information is required.

- Earliest date Opportunity Service is expected to be used:_____
- Requested Opportunity Capacity: _____MW (Demand in excess of DTS Contract Capacity)
- Proposed use of the electricity to be obtained under DOS, and anticipated consumption profile:

  Please provide this, labeled "Schedule A".
- *Eligibility:* ***Please read the Commercial Eligibility Criteria of the ~~TA~~AESO's Business Practices for Demand Opportunity Services (DOS)*** *and provide a brief explanation, labeled "Schedule B", of how the proposed use of DOS meets the criteria.*
- Referring to the Commercial Eligibility Criteria, which of the following applies? (Check one):

1. Alternative Source of Energy ☐ 2. No Alternative Source of Energy ☐ 3.Generator Maintenance ☐

- What will the applicant do if DOS is not available as requested?_____
  ___
- For what period of time does the applicant expect the qualifying criteria to persist?__
  _____

CONFIDENTIALITY

Prior to submitting this application, the applicant may request the ~~TA~~AESO to sign a confidentiality agreement. May the ~~TA~~AESO disclose information from this application to the interconnecting Transmission Facility Owner, on a need-to-know basis? Yes _____
_____No_____

DEMAND OPPORTUNITY SERVICE
STAGE 1 APPLICATION FOR OPPORTUNITY SERVICE

Stage 1 Application for Demand Opportunity Service (DOS) -- Preliminary Assessment

ATTACHMENTS TO BE PROVIDED BY THE APPLICANT

- Schedule A: Proposed use of the electricity to be obtained under DOS, and anticipated consumption profile
- Schedule B: Explanation of how the proposed use of DOS meets the Commercial Eligibility Criteria

The applicant acknowledges that this document is not a contract between itself and the ~~Transmission Administrator~~Alberta Electric System Operator.

Applicant:_____ Date: _____

(The applicant may be the end user or the Customer at Stage 1; however, the Stage 2 applicant must be a DTS Customer of the ~~TA~~AESO.)

Name: _____Title: _____

Please complete and send to ~~Transmission Administrator of Alberta~~ Electric System Operator.

Mail: 900, 736 – 8 Avenues S.W.
Calgary, Alberta T2P 1H4
Fax: (403) 266-~~2128~~

DEMAND OPPORTUNITY SERVICE
STAGE 2 APPLICATION FOR OPPORTUNITY SERVICE

Stage 2 Application for Demand Opportunity Service (DOS)
Pre-qualification

It is suggested that a Stage 1 Application (preliminary assessment) be made before making this Stage 2 Application. The applicant should be familiar with the information on Opportunity Service that appears on the ~~TA~~AESO's website, including the ~~TAI~~AESO's Business Practices for Demand Opportunity Service, the ~~TA~~AESO's Terms and Conditions of Service, and the Rate Schedules. This application does not bind the ~~TA~~AESO or the applicant to any contractual terms or conditions. A non-refundable fee of $5000.00 is payable with this application.

IDENTIFICATION OF APPLICANT AND THE END USER

Applicant: _____
(Must be an existing DTS Customer of the ~~TA~~AESO)

End User Name: _____
(Need not be a direct Customer of the ~~TA~~AESO)

Primary Contact: Name: _____ **Company:** _____
(May be the end user, at the discretion of the Applicant.)

Phone: _____ **Fax:** _____ **Email:** _____

Facility Name: _____
Facility Location: LSD____**SEC**_____**TWP**_____**RGE**_____**MER**____
Connected AIES Substation (Name and Number): _____

Point of Delivery (POD): _____
(Description of the Point of Delivery)

Has a Stage 1 Application been submitted for this proposed use of DOS? Yes _____**No**_____

TECHNICAL AND COMMERCIAL INFORMATION

The following information is required in order for the ~~TA~~AESO to assess whether the proposed use of DOS complies with the ~~TA~~AESO's Terms and Conditions of Service and meets the technical and commercial eligibility criteria.

- **Earliest date Opportunity Service is expected to be used:** _____
- **Requested Opportunity Capacity:**_____ MW (Maximum demand in excess of DTS Contract Capacity)
- **Type of Opportunity Service expected to be used:** DOS 7 minute ___DOS 1 Hour ___DOS Standard___
  (This indication does not preclude the use of other types of Opportunity Service.)
- **Technical Information:** *Please provide the following, labeled **"Schedule A".***
  1. Load Characteristic (static, synchronous machine, or induction machine).
  2. Approximate load factor.

3. Expected power factor.

- **Commercial Information**: ***Please read the Commercial Eligibility Criteria of the ~~TA~~AESO's Business Practices for Demand Opportunity services (DOS)*** *and* ***provide a comprehensive Business Case, labeled "Schedule B",*** *demonstrating that the proposed use of DOS complies with these criteria. The Business Case must provide enough information to satisfy the ~~TA that~~ AESO that the proposed use of electricity under DOS would not occur at the standard rate schedule (DTS). The Business Case normally pertains to the end user's commercial circumstances, and the end user must be prepared to provide any additional information that the ~~TA~~AESO reasonably requests.*
- For what period of time does the applicant expect the qualifying criteria to persist?___

(This information does not limit the pre-qualification to this time period.)

DEMAND OPPORTUNITY SERVICE
STAGE 2 APPLICATION FOR OPPORTUNITY SERVICE

Stage 2 Application for Demand Opportunity Service (DOS) – Pre-qualification

CONFIDENTIALITY

Prior to submitting this application, the applicant may request the ~~TA~~AESO to sign a confidentiality agreement. May the ~~TA~~AESO disclose information from this application to the interconnecting Transmission Facility Owner, on a need-to-know basis? Yes ____ _____No_____

ATTACHMENTS TO BE PROVIDED BY THE APPLICANT

- Schedule A: Technical information describing the proposed use of DOS
- Schedule B: Business Case demonstrating that the proposed use of DOS meets the Commercial Eligibility Criteria

The Applicant confirms that the contents of this application are true.

Applicant:_____ Date:_____
(The applicant must be a DTS Customer of the ~~TA~~AESO.)

Name: _____Title: _____

Please complete and send to ~~Transmission Administrator of~~ Alberta Electric System Operator
Mail: 900, 736 – 8 Avenues S.W.
Calgary, Alberta T2P 1H4
Fax: (403) 266-~~2128~~2959

The ~~Transmission Administrator of~~ Alberta Electric System Operator acknowledges that this application was received on the indicated date, together with the prescribed fee.

_____ Fee paid: $___
(Date)

Signature: _____

Name: _____Title: _____

~~TA~~ Alberta Electric System Operator Internal Use Only

Corporate Finance

Application approved or denied:_____

Signature:_____Date:_____

Name:_____Title:_____

Technical Services Operational Planning

Application approved or denied:_____

Approved application checklist: Loss Factor (Y/N):_ Pre-qualify List addition (Y/N):_____

Signature:_____Date:_____

Name:_____Title:_____

SYSTEM ACCESS SERVICE AGREEMENT
DEMAND OPPORTUNITY SERVICE

	OP-224
~~*Transmission Administrator of*~~ *Alberta Electric System Operator* *Operating Policy OP-224* **Opportunity Service**	**Issue Date:** 2002-05-01 **Effective Date:** 2002-05-01 **Expiry Date:** Annual **Revision No.:** 1

Appendix A: DOS Request

_____ - _____ Check box if this Request overlaps with a previous DOS Request or DOS Transaction ☐

Pre-qualification Number | Request number provided by Customer

The Customer is to complete this document, and fax it to the System Controller to request a DOS Transaction. The Customer must follow up by phoning the SC. (Fax: 403-261-7864) (Ph: 403-233-6420)

Demand Opportunity Service (DOS), according to the terms herein, will be available only after the System Controller approves this DOS Request ~~on behalf of the Transmission Administrator~~.

Identification

_____ requests Opportunity Service (subject to confirmation of available
Customer or Customer's Agent

capacity) in accordance with the Pre-qualification granted by the ~~Transmission Administrator~~Alberta Electric System Operator, identified by Pre-qualification Number shown above, at _____
Description of the Point of Delivery

Terms of Transaction

The requested service is (indicate one): ___DOS Standard; ___DOS 7 minutes, ___DOS One hour

The transaction is to begin on: _____ (Start Date) at _____ (Start time)

The transaction will be completed on: _____ (End Date) at _____ (End time)

A DOS Transaction must start and end at the top of an hour, and cannot start within 60 minutes of the time the DOS Request is faxed. The minimum Term is 8 hours; End Date must occur in the same calendar month as the Start Date

The requested Capacity is _____ MW (cannot exceed the Opportunity Capacity)

Applicant's Endorsement

Submitted by: _____ (Customer's Representative (please print)) on _____ (date) at _____ (time)

Signature: _____ (Customer's Representative) Phone: _____ Fax: _____

Approval/Denial by the System Controller ~~on behalf of the TA~~.

Submitted by: _____ (System Controller's Representative (please print)) on _____ (date) at _____ (time)

Signature: _____
System Controller's Representative

Approved: ☐ Denied: ☐ If denied, please indicate the reason below:

The request does not comply with the SC's information on pre-qualified DOS customers: ☐

The requested Opportunity Capacity is unavailable at the time requested: ☐

System Controller's comments: _____

_____

_____

SYSTEM ACCESS SERVICE AGREEMENT
EXPORT SERVICE

The following constitute the terms pursuant to which the ~~Transmission Administrator (TA~~Independent System Operator, a corporation carrying on business under the trade name Alberta Electric System Operator (AESO) shall provide System Access to the Customer: (Defined terms used herein without definition shall have the meanings ascribed thereto in the Terms and Conditions of the ~~Transmission Administrator~~AESO's Tariff).

1. TYPE OF SERVICE

Service under this contract shall be pursuant to Rate Schedule Export Service (ES).

2. POINT OF EXPORT

❑ British Columbia Intertie ❑ Saskatchewan Intertie

3. EFFECTIVE DATE

_____ __, 2001

4. TERM

_____Days [Months]

5. RATES AND TERMS OF SERVICE

The supply of System Access Service under this Agreement shall be pursuant to the ~~Transmission Administrator~~AESO's Tariff.

6. NOTICES

Notices sent to the Customer pursuant to this Agreement shall be as follows:

Invoices:	Attention:	_____
	Address:	_____
		_____
		_____
	Fax:	_____
All other notices:	Attention:	_____
	Address:	_____
		_____
		_____
	Fax:	_____

By executing in the space below, the Customer and the ~~Transmission Administrator~~AESO agree to the foregoing provisions.

~~**Transmission Administrator of Alberta**~~

~~Per: _____~~
~~Name: _____~~
~~Title: _____~~

Independent System Operator a corporation carrying on business under the trade name Alberta Electric System Operator

Per: _____
~~Name:~~Date: _____
Tony Demassi

~~Title:~~ Director, Customer Relations

Per: _____ Date: _____
Name: _____
Title: _____

Per: _____
~~Customer~~ Date: _____
Name: _____
Title: _____

_____
~~Signature~~

SYSTEM ACCESS SERVICE AGREEMENT
SUPPLY TRANSMISSION SERVICE

The following constitute the terms pursuant to which the ~~Transmission Administrator (TA~~Independent System Operator, **a corporation carrying on business under the trade name Alberta Electric System Operator** (AESO) shall provide System Access to the Customer. (Defined terms used herein without definition shall have the meanings ascribed thereto in the Terms and Conditions of the ~~Transmission Administrator~~AESO's Tariff).

1. TYPE OF SERVICE

System Access Service shall be provided pursuant to Rate Schedule Supply Transmission Service (STS).

2. POINT OF INTERCONNECTION WITH THE TRANSMISSION SYSTEM

(a) Point of Supply (POS): The POS shall be [description, e.g. relative to Substation]

(b) Location:
Township_____ Range_____ W____M

3. CONTRACT CAPACITY

"x" MW

4. COMMISSIONING PERIOD FOR NEW TRANSMISSION FACILITIES, IF ANY

5. EFFECTIVE DATE

_____ __, 2001

6. CUSTOMER CONTRIBUTION

The Customer Contribution charge is $_____.

7. RATES AND TERMS OF SERVICE

The supply of System Access Service pursuant to this Agreement and the Customer's obligations with respect to connection and supply of System Support Services shall be subject to the ~~Transmission Administrator~~AESO's Tariff, in particular to the Rate Schedule referenced under Paragraph 1.

8. NOTICES:

Notices sent to the Customer pursuant to this Agreement shall be as follows:

Invoices:	Attention:	_____
	Address:	_____
		_____
		_____
	Fax:	_____
All other notices:	Attention:	_____
	Address:	_____
		_____
		_____
	Fax:	_____

By executing in the space below, the Customer and the ~~Transmission Administrator~~AESO agree to the foregoing provisions.

~~Transmission Administrator of Alberta~~
Independent System Operator a corporation carrying on business under the trade name Alberta Electric System Operator

Per: _____ Date:
~~Name:~~ _____

~~Title:~~ Tony Demassi
Director, Customer Relations

Per: _____ Date:
Name: _____
Title _____

Per: _____
~~Customer~~Date:
Name:
Title

_____
~~Signature~~

SYSTEM ACCESS SERVICE AGREEMENT
IMPORT SERVICE

The following constitute the terms pursuant to which the ~~Transmission Administrator (TA~~Independent System Operator, **a corporation carrying on business under the trade name Alberta Electric System Operator** (AESO) shall provide System Access to the Customer. (Defined terms used herein without definition shall have the meanings ascribed thereto in the Terms and Conditions of the ~~Transmission Administrator~~AESO's Tariff).

1. TYPE OF SERVICE

Service under this contract shall be pursuant to Rate Schedule Import Service (IS).

2. POINT OF INTERCONNECTION WITH THE TRANSMISSION SYSTEM

❑ British Columbia Intertie ❑ Saskatchewan Intertie

3. EFFECTIVE DATE

_____ __, 2001

4. TERM

_____Days

5. RATES AND TERMS OF SERVICE

The supply of System Access Service pursuant to this Agreement shall be subject to the ~~Transmission Administrator~~AESO's Tariff, in particular to the Rate Schedule referenced under Paragraph 1.

6. NOTICES

Notices sent to the Customer pursuant to this Agreement shall be as follows:

Invoices: Attention: _____
Address: _____
_____
_____
Fax: _____

All other notices: Attention: _____
Address: _____
_____
_____
Fax: _____

By executing in the space below, the Customer and the ~~Transmission Administrator~~AESO agree to the foregoing provisions.

~~Transmission Administrator of Alberta~~
Independent System Operator a corporation carrying on business under the trade name Alberta Electric System Operator

Per: _____
~~Name:~~Date: _____
Tony Demassi

~~Title:~~ Director, Customer Relations

Per: _____
~~Name:~~Date: _____
Name:
~~Title:~~ _____
Title: _____

Per: _____ Date: _____
Name: _____
Title: _____

_____
~~Customer~~

_____
~~Signature~~

Appendix "C"

Construction Commitment Agreement Proforma

THIS AGREEMENT is effective on _____ (the "Effective Date")

BETWEEN:

~~Transmission Administrator of Alberta~~
~~A Corporation incorporated~~**Independent System Operator a corporation carrying on business under the** ~~Business Corporations Act (~~**trade name Alberta**~~)~~ **Electric System Operator**
(hereinafter referred to as the "~~Transmission Administrator or the "TA~~AESO")

-and-

(Insert name of party)
A corporation incorporated under the Business Corporations Act (Insert Jurisdiction)
(hereinafter referred to as the "Customer")

INTRODUCTION

1. The Customer has requested System Access Service from ~~the Transmission Administrator~~ AESO and intends to enter into a System Access Service Agreement with the ~~TA~~AESO. The granting of System Access Service to the Customer will necessitate the construction of new transmission facilities and a commitment by the Transmission Administrator in relation to the expenditure of capital for such construction (the "Proposed Project").

2. Upon execution of this Construction Commitment Agreement, the Transmission Administrator shall begin implementing plans to complete the Proposed Project. Both the Transmission Administrator and its contractors must be held harmless from any negative financial consequences emanating from a decision by the Customer to discontinue, postpone or cancel the Proposed Project.

AGREEMENT

1. The ~~Transmission Administrator~~AESO and the Customer agree to the following:

   (a) This Agreement shall take effect on the Effective Date and shall remain in effect until execution of the System Access Service Agreement by the ~~Transmission Administrator~~AESO and the Customer;

   (b) If the Customer terminates the Proposed Project or fails to execute the System Access Service Agreement within 30 days after the completion of

the Proposed Project, the Proposed Project shall be deemed to have been cancelled and the Customer shall immediately reimburse the ~~Transmission Administrator~~AESO for the aggregate amount of costs and expenses, as well as any losses, damages, penalties or other claims it may incur or be subject to howsoever arising from the Proposed Project ("Cancellation Costs"), and which are incurred by the ~~Transmission Administrator~~AESO or its contractors relating to facilities planning and design, the competitive procurement process (if any), material and right-of-way procurements and construction of the Proposed Project (including without limitation all cancellation penalties and salvage and reclamation costs);

(c) In the event that the Customer terminates the Proposed Project prior to its completion, the ~~Transmission Administrator~~AESO shall use, and shall cause its contractors to use, reasonable commercial efforts to minimize the amount of the Cancellation Costs to the extent such is within their control;

(d) The Customer shall pay the Cancellation Costs immediately upon demand by the ~~TA~~AESO. In the event that the Customer fails to pay the ~~Transmission Administrator~~AESO upon demand, the ~~Transmission Administrator~~AESO shall be entitled to charge the Customer 1.5% per month interest on late payment of all amounts due to the ~~TA~~AESO; and

(e) In the event that the Customer has not paid all of the Cancellation Costs to the ~~Transmission Administrator~~AESO within seven (7) days of receipt by the Customer of the ~~Transmission Administrator~~AESO's demand therefor, the ~~Transmission Administrator~~AESO shall be entitled to realize fully upon any and all security provided by the Customer as assurance of payment, which security is attached hereto as Schedule "A".

2. The ~~Transmission Administrator~~AESO's Tariff form part of this Agreement and in the event of any conflict between the provisions hereof and those of the ~~Transmission Administrator~~AESO's Tariff, the ~~Transmission Administrator~~AESO's Tariff shall prevail.

THE CUSTOMER AND THE ~~Transmission Administrator~~AESO have executed this Agreement on the Effective Date:

~~Transmission Administrator of Alberta~~Independent System Operator, a corporation carrying on business under the trade name as **Alberta Electric System Operator (AESO).**

Per: _____

Per: _____

(INSERT CUSTOMER'S NAME)

Per: _____

Per: _____

Appendix "D"

Metering Equipment Information

1. For each POS Meter:

   (a) Company identification
   (b) Meter type identification
   (c) Meter serial number
   (d) Date meter installed
   (e) Date meter removed
   (f) Number of elements
   (g) Manufacturer
   (h) Model
   (i) Measurement Canada approval
   (j) Past test dates
   (k) Past results (pass/fail information only)
   (l) Planned test dates

2. For each POS meter recorder:

   (a) Record identification
   (b) Recorder type
   (c) Serial number
   (d) Date installed
   (e) Date removed
   (f) Manufacturer
   (g) Model
   (h) Measurement Canada approval
   (i) Past test dates
   (j) Past results (pass/fail information only)
   (k) Planned test dates

3. For each Current Transformer associated with POS metering:

   (a) Company identification
   (b) Transformer type
   (c) Serial number
   (d) Date installed
   (e) Date removed
   (f) Phase location
   (g) Ratio
   (h) Accuracy
   (i) Manufacturer
   (j) Model
   (k) Measurement Canada approval

4. For each Potential Transformer associated with POS metering:

   (a) Company identification
   (b) Transfer type
   (c) Serial number
   (d) Date installed
   (e) Date removed
   (f) Phase location
   (g) Ratio
   (h) Accuracy
   (i) Manufacturer
   (j) Model
   (k) Measurement Canada approval

Appendix E
Regulated Generating Units

Generating Unit	Owner	Type of Plant	Base Life
Barrier #1	TAU	Hydro	2013
Battle River #3	AE	Coal-fired thermal	2009
Battle River #4	AE	Coal-fired thermal	2009
Battle River #5	AE	Coal-fired thermal	2021
Bearspaw #1	TAU	Hydro	2013
Bighorn #1	TAU	Hydro	2032
Bighorn #2	TAU	Hydro	2032
Braseau #1	TAU	Hydro	2025
Braseau #2	TAU	Hydro	2025
Cascade #1	TAU	Hydro	2013
Cascade #2	TAU	Hydro	2013
Clover Bar #1	EPGI	Gas-fired thermal	2010
Clover Bar #2	EPGI	Gas-fired thermal	2010
Clover Bar #3	EPGI	Gas-fired thermal	2010
Clover Bar #4	EPGI	Gas-fired thermal	2010
Genesee #1	EPGI	Coal-fired thermal	2029
Genesee #2	EPGI	Coal-fired thermal	2029
Ghost #1	TAU	Hydro	2013
Ghost #2	TAU	Hydro	2013
Ghost #3	TAU	Hydro	2013
Ghost #4	TAU	Hydro	2013
Horseshoe #1	TAU	Hydro	2013
Horseshoe #2	TAU	Hydro	2013
Horseshoe #3	TAU	Hydro	2013
Horseshoe #4	TAU	Hydro	2013
H.R. Milner	AE	Coal-fired thermal	2012
Interlakes #1	TAU	Hydro	2013
Kananaskis #1	TAU	Hydro	2013
Kananaskis #2	TAU	Hydro	2013
Kananaskis #3	TAU	Hydro	2013
Keephills #1	TAU	Coal-fired thermal	2023
Keephills #2	TAU	Coal-fired thermal	2023
Pocaterra #1	TAU	Hydro	2013
Rainbow #1	AE	Gas turbine	2005
Rainbow #2	AE	Gas turbine	2005
Rainbow #3	AE	Gas turbine	2005
Rossdale #8	EPGI	Gas-fired thermal	2000
Rossdale #9	EPGI	Gas-fired thermal	2000
Rossdale #10	EPGI	Gas-fired thermal	2000
Rundle #1	TAU	Hydro	2013
Rundle #2	TAU	Hydro	2013

Generating Unit	Owner	Type of Plant	Base Life
□ Generating Unit	Owner	Type of Plant	Base Life
Sheerness #1	AE/TAU	Coal-fired thermal	2026
Sheerness #2	AE/TAU	Coal-fired thermal	2026
Spray #1	TAU	Hydro	2013
Spray #2	TAU	Hydro	2013
Sturgeon #1	AE	Gas turbine	1998
Sturgeon #2	AE	Gas turbine	1998
Sundance #1	TAU	Coal-fired thermal	2010
Sundance #2	TAU	Coal-fired thermal	2010
Sundance #3	TAU	Coal-fired thermal	2020
Sundance #4	TAU	Coal-fired thermal	2020
Sundance #5	TAU	Coal-fired thermal	2020
Sundance #6	TAU	Coal-fired thermal	2020
Three Sisters #1	TAU	Hydro	2013
Wabamun #1	TAU	Coal-fired thermal	2003
Wabamun #2	TAU	Coal-fired thermal	2003
Wabamun #3	TAU	Coal-fired thermal	2003
Wabamun #4	TAU	Coal-fired thermal	2003

APPENDIX 3

Revised Total Revenue Requirement

TA 2002 and 2003 Revenue Requirement
($ millions)

	2003 Forecast	2002 Approved	2002 Actual[1]
Wires Costs			
ATCO Electric Ltd.	132.6	120.6	120.4
City of Lethbridge	2.8	2.8	2.8
City of Red Deer	1.8	1.8	1.8
ENMAX Power Corporation	34.4	27.9[2]	27.6
EPCOR Transmission Inc.	34.0	34.0	34.0
TransAlta	2.7	164.9	55.0
Aquila Networks (Farm)	1.9	1.3	1.3
AltaLink	133.3	Not Applicable[3]	109.9
Subtotal Wires	**343.5**	**353.0**	**352.8**
Foster Creek Substation (ATCO Utilities Services)	1.4	1.5	1.5
Credits (IBOC)	2.7	8.3	2.9
Credits (LBC SO)	3.9	0.4	0.2
Capital Additions	1.1	12.3	2.4
Isolated Generation	(6.1)	12.7	12.8
Total Wires	**346.5**	**388.5**	**372.6**
Ancillary Services Costs			
Operating Reserves			
Regulating	48.2	49.0	41.1
Spinning	49.3	63.5	53.0
Supplemental	24.7	23.6	22.7
Standby	44.8	8.9	39.0
Subtotal Reserves	**167.0**	**145.0**	**155.8**
Under Frequency Mitigation	5.2	5.3	5.0
Transmission Must Run	26.1	16.7	55.5[4]
Fort Saskatchewan Load Shed	0.9	0.8	0.8
Hydro Motoring	4.2	4.2	4.2

[1] The 2002 actual costs represent actual costs to the end of November 2002 and a forecast of costs for December 2002.

[2] This includes an approved revenue requirement of $27.6M plus $0.3M for the Beddington Substation.

[3] The 2002 interim approved wire costs for AltaLink are included in the TransAlta amounts for 2002.

[4] The 2002 actual costs for transmission must run reflect invoiced amounts and incorporate changes arising from Board Decision 2002-103.

TA 2002 and 2003 Revenue Requirement
($ millions)

	2003 Forecast	2002 Approved	2002 Actual[4]
Subtotal	**36.4**	**27.0**	**65.5**
Remedial Action Schemes	0.4	0.7	0.4
Black Start	2.2	1.5	1.5
Subtotal RAS/Black Start	**2.6**	**2.2**	**1.9**
ILRAS	0.5	0.7	0.4
Poplar Hill	1.9	1.8	1.8
Total Ancillary Services Costs	**208.4**	**176.7**	**225.4**
Losses			
Pool Payment	142.7	164.9	114.8
Losses Studies Surcharge	0.0	0.7	0.7
Total Losses	**142.7**	**165.6**	**115.5**
Other Industry Costs			
System Controller Shared Costs	3.6	3.4	3.4
Regulatory Hearing Costs	9.8	1.0	2.2
WECC	1.0	1.1	1.0
TA Share of Board Overhead	1.6	Not Applicable	1.6
Total Other Industry Costs	**16.0**	**5.5**	**8.2**
TA Costs			
Administration Costs	12.9	12.0	12.4
Interest, Return on Investment & Amortization and Depreciation	1.6	2.0	(0.5)
Management Fee	0.0	4.8	4.4
ISO Transition Costs	1.2	Not Applicable	Not Applicable
Tariff Def. Cor. Regulation Fee	4.9	Not Applicable	Not Applicable
Total TA Costs	**20.6**	**18.8**	**16.3**
Other			
Engage Settlement Refund Adj.	(1.9)	Not Applicable[5]	Not Applicable[6]
Total Other	(1.9)		
TOTAL REVENUE REQUIREMENT	**732.4**	**755.1**	**738.0**

[5] The 2002 interim approved wire costs for AltaLink are included in the TransAlta amounts for 2002.

[6] The 2002 interim approved wire costs for AltaLink are included in the TransAlta amounts for 2002.

Revised Attachment 7 (Phase 2) to the 2003 General Tariff Application

Tariff Rate Calculations

	All Hours	Units
Assumptions		
Energy Supplied	53,785,080	MWh
Energy Consumed	50,902,213	MWh
Average Pool Price	47.93	$/MWh
Demand MW-Months	107,137.0	MW-months
Regulated Supply MW-Months	88,024.8	MW-months
Wires Costs, TA Costs, and Other Industry Costs	381.3	M$
58% allocation to load customers	221.2	M$
less: load-related opportunity revenues	0.7	M$
equals net load-related wires cost	221.9	M$
60% demand-related	133.1	M$
divided by Demand MW-Months	107,137.0	MW-months
DTS Wires Demand Charge	1,242.71	$/MW/month
40% energy-related	88.8	M$
divided by All Hours Energy Consumed	50,902,213	
DTS Wires Energy Charge	$ 1.7437	$/MWh
42% allocation to supply customers	160.1	M$
less: supply-related opportunity revenue	-4.0	M$
less: local generation connection cost	-30.6	M$
equals net supply-related wires cost	125.5	M$
100% energy-related	125.5	M$
divided by All Hours Energy Supplied	53,785,080	MWh
STS Wires Energy Charge	2.334	$/MWh
local generation connection assets	30.6	M$
divided by Regulated Supply MW-Months	88,024.8	MW-months
Regulated Generating Unit Connection Charge	348	$/MW/month
System Support Services	169.6	M$
50% allocated to supply customers, 100% energy-related	84.8	M$
STS System Support Services (SSS) Charge	3.289% x MWh x Pool Price	
50% allocated to load customers, 100% energy-related	84.8	
DTS System Support Services (SSS) Charge	3.476% x MWh x Pool Price	
Voltage Control, TMR/SMR, Under Frequency Mitigation, and Hydro Motoring	36.4	
50% allocated to supply customers, 100% energy-related	18.2	
less power factor incentive charge	0	
equals	18.2	18.2
STS Voltage Control Charge	0.706% x MWh x Pool Price	
50% allocated to load customers, 100% energy-related	18.2	
DTS Voltage Control Charge	0.75% x MWh x Pool Price	
Voltage Control - Poplar Hill	1.9	
100% allocated to load customers, 100% demand-related	1.9	
divided by Demand MW-Months	107,137.0	
DTS Poplar Hill Charge	17.73	$/MW/month
Remedial Action Schemes (including ILRAS)	0.5	
100% allocated to load customers	0.5	
60% demand-related	0.3	
divided by Demand MW-Months	107,137.0	
DTS RAS Demand Charge	2.80	$/MW/month
40% energy-related	0.2	
divided by All-Hours Energy Consumed	50,902,213	
DTS RAS Variable Charge	0.0039	$/MWh

REVISED ATTACHMENT 10 (PHASE II)

TRANSMISSION ADMINISTRATOR of ALBERTA

2003 TARIFF
RATE SCHEDULES

TABLE OF CONTENTS

CODE	DESCRIPTION	PAGE No.
DTS	Demand Transmission Service	3
DOS (7 minutes)	Demand Opportunity Service (7 minutes)	4
DOS (1 hour)	Demand Opportunity Service (1 hour)	6
DOS (Term)	Demand Opportunity Service (Term)	9
ES	Export Service	10
UFS	Demand Under Frequency Load Shedding Credits	11
COS	Demand Customer Owned Substation Credit	12
STS	Supply Transmission Service	13
IS	Import Service	14
Appendix A	Rate Riders	
	Rate Rider A1 – Dow Chemical Transmission Duplication Avoidance Adjustment	17
	Rate Rider A2 – Nova Chemicals Transmission Duplication Avoidance Adjustment	18
	Rate Rider A3 – Shell Scotford Transmission Duplication Avoidance Adjustment	22
	Rate Rider A4 – Imperial Oil Resources Limited Transmission Duplication Avoidance Adjustment	27
	Rate Rider B – Working Capital Deficiency / Surplus	31
	Rate Rider C – Deferral Account Adjustment Ride	32
	Rate Rider D – Transmission Administrator Tariff Deficiency Correction Regulation Rider	34
Appendix B	Maximum Continuous Rating for Regulated Generation units under Rate STS	33

Rate Schedule – Demand Transmission Service (DTS)

Applicable to: Demand Customers

Rate: Charges for the DTS in any one Billing Period shall be the sum of the Interconnection Charge, the Operating Reserve Charge and the Other System Support Services Charge, where:

The Interconnection Charge equals:

$1,242.71 /MW/month of Billing Capacity in the Billing Period, plus
$1.75/MWh of Metered Energy during the Billing Period.

Billing Capacity shall be the highest of:
(i) The highest fifteen (15) minute Metered Demand in the Billing Period;
(ii) The Ratchet Level; or
(iii) 90% of the Contract Capacity.

where "Ratchet Level" is defined as the highest of the following:

(i) 90% of the highest Metered Demand in the past 12 months;
(ii) 85% of the highest Metered Demand in the past 24 months;
(iii) 80% of the highest Metered Demand in the past 36 months;
(iv) 75% of the highest Metered Demand in the past 48 months;
(v) 70% of the highest Metered Demand in the past 60 months.

The Operating Reserve Charge equals:

Metered Energy in each hour X 4.22% X Pool Price.

The Other System Support Services Charge equals:

$19.04/MW/month of highest Metered Demand in the Billing Period, plus a charge (where Power Factor is less than 90%) of $400/MVA applied to the difference between the highest metered Apparent Power and 111% of the highest Metered Demand during the same Billing Period.

Terms: The rate is separately applicable at each POD.

References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with paragraphs 6.2 and 6.3 of the Terms and Conditions.

The Terms and Conditions form part of this Rate Schedule.
Rate Riders A&B apply to these customers when invoked by the TA.

Rate Schedule – Demand Opportunity Service (DOS 7 Minutes)

Applicable to: Qualified Opportunity Service Customers who are recallable within 7 minutes.

Available: For quantities of Metered Energy taken within the Opportunity Capacity for the relevant System Access Service Agreement for Demand Opportunity Service, and when sufficient transmission capacity exists to accommodate such quantity. This service will be available a minimum of one (1) hour for Customers deemed eligible in the pre-qualification process, following the execution of a System Access Service Agreement.

Rate: The charges for service per Billing Period shall be as follows:

(1) The greater of (a) and (b) below:

(a)

(i) $3.00/MWh of Metered Energy during the Billing Period; plus

(ii) Incremental Losses Charge, calculated as the sum over each transaction hour of the Billing Period of the following:

Metered Energy in hour x location specific loss factor x Pool Price for the hour, where the location specific loss factor is an incremental factor determined by the TA for each Point of Delivery.

(b) A minimum charge equal to:

Opportunity Capacity under this Rate Schedule x number of hours in total transactions in the Billing Period x 75% x $3.00/MWh.

Plus

(2) Transaction Fee: $500 per Billing Period.

Terms: The rate is separately applicable at each POD.

A Customers pre-qualified eligibility for Demand Opportunity Service will be available for a maximum of one (1) year. The maximum term for a System Access Services Agreement for Demand Opportunity Service will be one (1) calendar month.
To the extent practicable, service for Opportunity Service Customers taking service under this Rate Schedule shall be recallable in advance of service for Non-Recallable Customers in an Emergency.

In the event that a Customer's service is recalled, Customer shall be required to curtail load by the amount directed by the System Controller, which can be an

amount up to the Opportunity Capacity, subject to no requirement on the Customer to curtail to below the DTS Contract Capacity. Curtailment of such amount shall be achieved within seven (7) minutes of receiving a directive from the System Controller.

References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with paragraphs 6.2 and 6.3 of the Terms and Conditions.

The Terms and Conditions form part of this Rate Schedule.

Rate Schedule – Demand Opportunity Service (DOS 1 Hour)

Applicable to: Qualified Opportunity Service Customers who are recallable within one (1) hour.

Available: For quantities of Metered Energy taken within the Opportunity Capacity for the relevant System Access Service Agreement for Demand Opportunity Service, and when sufficient transmission capacity exists to accommodate such quantity. This service will be available a minimum of one (1) hour for Customers deemed eligible in the pre-qualification process, following the execution of a System Access Service Agreement.

Rate: The charges for service per Billing Period shall be as follows:

(1) the greater of (a) and (b) below:

(a)

(i) $5.00/MWh of Metered Energy during the Billing Period; plus

(ii) Incremental Losses Charge, calculated as the sum over each transaction hour of the Billing Period of the following:

Metered Energy in hour x location specific loss factor x Pool Price for the hour, where the location specific loss factor is an incremental factor determined by the TA for each Point of Delivery.

(b) A minimum charge equal to:

Opportunity Capacity under this Rate Schedule x number of hours in total transactions in the Billing Period x 75% x $5.00/MWh.

Plus

(2) Transaction Fee: $500 per Billing Period.

Terms: The rate is separately applicable at each POD.

A Customers pre-qualified eligibility for Demand Opportunity Service will be available for a maximum of one (1) year. The maximum term for a System Access Services Agreement for Demand Opportunity Service will be one (1) calendar month.

To the extent practicable, service for Opportunity Service Customers taking service under this Rate Schedule shall be recallable in advance of service for Non-Recallable Customers in an Emergency.

In the event that a Customer's service is recalled, Customer shall be required to curtail load by the amount directed by the System Controller, which can be an amount up to the Opportunity Capacity, subject to no requirement on the Customer to curtail to below the DTS Contract Capacity. Curtailment of such amount shall be achieved within one (1) hour of receiving a directive from the System Controller.

The amount of Metered Energy attributable to service under this Rate Schedule shall be determined in accordance with paragraphs 6.2 and 6.3 of the Terms and Conditions.

The Terms and Conditions form part of this Rate Schedule.

Rate Schedule – Demand Opportunity Service (DOS Term)

Applicable to: Qualified Opportunity Service Customers

Available: For quantities of Metered Energy taken within the Opportunity Capacity for the relevant System Access Service Agreement for Demand Opportunity Service, and when sufficient transmission capacity exists to accommodate such quantity. This service will be available a minimum of one (1) hour for Customers deemed eligible in the pre-qualification process, following the execution of a System Access Service Agreement.

Rate: The charges for service per Billing Period shall be as follows:

(3) The greater of (a) and (b) below:

(a)

(i) $20.00/MWh of Metered Energy during the Billing Period; plus

(ii) Incremental Losses Charge, calculated as the sum over each transaction hour of the Billing Period of the following:

Metered Energy in hour x location specific loss factor x Pool Price for the hour, where the location specific loss factor is an incremental factor determined by the TA for each Point of Delivery.

(b) A minimum charge equal to:

Opportunity Capacity under this Rate Schedule x number of hours in total transactions in the Billing Period x 75% x $20.00/MWh.

Plus

(4) Transaction Fee: $500 per Billing Period.

Terms: The rate is separately applicable at each POD.

A Customers pre-qualified eligibility for Demand Opportunity Service will be available for a maximum of one (1) year. The maximum term for a System Access Services Agreement for Demand Opportunity Service will be one (1) calendar month.

To the extent practicable, service for Opportunity Service Customers taking service under this Rate Schedule shall be recallable in advance of service for Non-Recallable Customers in an Emergency.

References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with paragraphs 6.2 and 6.3 of the Terms and Conditions.

The Terms and Conditions form part of this Rate Schedule.

Rate Schedule – Export Service (ES)

Applicable to: Customers exporting electric energy from the AIES.

Available: When sufficient transmission capacity exists to accommodate the capacity scheduled for service, and this service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Export Service.

Rate: The charges for service per Billing Period shall be as follows:

(5) The greater of (a) and (b) below:

(a)

(i) $2.33/MWh of Energy Transfer during the Billing Period; plus

(ii) Incremental Losses Charge, calculated as the sum, over all transaction hours in the Billing Period of the following:

Energy Transfer in hour x location specific loss factor x Pool Price for the hour, where the location specific loss factor is an incremental factor determined by the TA for each Point of Exchange.

(b) A minimum charge, calculated as the sum, over all transactions in the Billing Period, of the following (where capacity scheduled is the hour-ahead scheduled amount for the transaction):

75% x capacity scheduled for Customer for the transaction x hours in the transaction x ($2.33/MWh + Incremental Losses Charge / Energy Transfer in Billing Period)

Plus

(6) An Operating Reserve charge or other System Support Service charge when, in the opinion of the TA, the transaction requires the procurement of incremental System Support Services and/or Operating Reserve.

Plus

(7) Transaction Fee: $500 per Billing Period.

Terms: System Access Service provided pursuant to this Rate Schedule is recallable on one (1) hour's notice. The rate is separately applicable at each Point of Exchange.

The Terms and Conditions form part of this Rate Schedule.

Rate Schedule – Demand Under-frequency Load Shedding Credit (UFS)

Purpose: The under-frequency load shedding credits compensate those Demand Customers who are connected to under-frequency load shedding devices and therefore face a higher risk of outage. In order to maintain the integrity of the AIES, the TA shall have the right to require each Demand Customer to maintain a minimum of 50% of that Customer's aggregate load (across all POD's through which the Customer takes System Access Service) connected to an under-frequency load shedding device.

Available to: Customers served under the DTS Rate Schedule who, as directed by the TA, install and activate an under frequency load shed relay satisfactory to the TA.

Rate: The credit is based on the relay setting and UFS Capacity for each relay setting. The TA provides no assurance as to the number or duration of any future outages.

UFS Capacity shall be the peak demand (expressed in MW) for each setting for which the Customer has agreed to be shed as set out in the System Access Service Agreement.

Relay Trip Setting	**Credit ($/kW of UFS Capacity/month)**
59.1 Hz	$0.065
58.9 Hz	$0.060
58.7 Hz	$0.055
58.5 Hz	$0.050
58.3 Hz	$0.045
58.1 Hz	$0.040
58.0 Hz	$0.035

Terms: The Terms and Conditions form part of this Rate Schedule.

Rate Schedule – Customer-Owned Substation Credit (COS)

Purpose: The Customer-Owned Substation Credit is to compensate customers who own their own substation, the cost of which are not included in the Transmission Administrator's revenue requirements.

Available to: DTS Customers who own their transmission station which steps the voltage down from transmission voltage to 25 kV or less, provided that the transmission station is fully operational and none of the costs of the transmission station are included in the Transmission Administrator's revenue requirements.

Rate: $700/MW/month of Billing Capacity in the Billing Period.

Terms: The Terms and Conditions form part of this Rate Schedule. The full Customer contribution pursuant to Article 9 is applicable to Customers eligible for this credit.

Rate Schedule – Supply Transmission Service (STS)

Applicable to: Customers who supply electrical energy to the AIES from within Alberta.

Rate: Charges for STS in any one Billing Period shall be the sum of the Interconnection Charge, the Losses Charge, and the Operating Reserve Charge, where:

The Interconnection Charge equals:

$2.33/MWh of Metered Energy during the Billing Period.

For the purpose of calculating the Interconnection Charge under this STS Rate Schedule Metered Energy shall be measured on a 15-minute interval.

The Losses Charge equals:

Metered Energy in each hour X location specific loss factor X Pool Price

Where "location specific loss factor" is determined by the Transmission Administrator for each Customer.

For the purpose of calculating the Losses Charge under this STS Rate Schedule Metered Energy shall be measured on a 15-minute interval.

Operating Reserves Charge equals:

Metered Energy in each hour X 4.0% X Pool Price.

Regulated Generating Unit Connection Costs:

An additional charge of $348/MW per month for each MW of unit MCR applicable only to regulated generating units, as that term is defined in the Act, as outlined in Appendix B of the rate schedules.

Terms: The rate is separately applicable at each POS.

References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with paragraphs 6.2 and 6.3 of the Terms and Conditions.

The Terms and Conditions form part of this Rate Schedule.
Rate Riders A&B apply to these customers when invoked by the TA.

Rate Schedule – Import Service (IS)

Applicable to: Customers importing electric energy into the AIES.

Available: When sufficient transmission capacity exists to accommodate the capacity scheduled for service, and this service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Import Service.

Rate: The charges for service per Billing Period shall be as follows:

(8) The greater of (a) or (b) below:

(a)

(i) $2.33/MWh of Energy Transfer during the Billing Period;

(ii) Incremental Losses Charge, calculated as the sum, over all transaction hours in the Billing Period of the following:

Energy Transfer in hour x location specific loss factor x Pool Price for the hour, where the location specific loss factor is an incremental factor determined by the TA for each Point of Exchange.

(b) A minimum charge, calculated as the sum, over all transactions in the Billing Period, of the following (where capacity scheduled is the hour-ahead scheduled amount for the transaction):

75% x capacity scheduled for Customer for the transaction x hours in the transaction x ($2.33/MWh + Incremental Losses Charge/Energy Transfer in the Billing Period)

Plus

(9) An Operating Reserve charge or other System Support Service charge when, in the opinion of the TA, the transaction requires the procurement of incremental System Support Services and/or Operating Reserve.

Plus

(10) Transaction Fee: $500 per Billing Period.

Terms: System Access Service provided pursuant to this Rate Schedule is recallable on one (1) hour's notice.

The rate is separately applicable at each Point of Exchange.

The Terms and Conditions form part of this Rate Schedule.

APPENDIX "A"

RATE RIDERS

Rate Rider A1

Transmission Duplication Avoidance Adjustment

Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2

Applicable to:	TransAlta Utilities Corporation / Aquila Canada Corp.
Available:	At certain Points of Delivery associated with Dow's facility, as more particularly described in Board Decision U98125 (Grid Company of Alberta Inc. – Transmission Avoidance Rate – Dow Transmission Bypass).
Rate:	Adjustment to otherwise applicable rates to be made in each Billing Period pursuant to the Decision.
Terms:	The Terms and Conditions form part of this Rate Rider.

Rate Rider A1
Transmission Duplication Avoidance Adjustment
Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2

Forecast of the benefit to the Transmission Administrator arising from the customer contributions made by Dow Chemicals Canada Inc. to TransAlta Utilities Corporation.

Year	Forecast Benefit to TA (Annual)	Forecast Benefit to TA (Monthly)
1998	$544,093	$45,341
1999	$865,378	$72,115
2000	$836,603	$69,717
2001	$807,828	$67,319
2002	$779,053	$64,921
2003	$750,278	$62,523
2004	$721,503	$60,125
2005	$692,728	$57,727
2006	$663,953	$55,329
2007	$635,178	$52,932
2008	$606,403	$50,534
2009	$577,628	$48,136
2010	$548,853	$45,738
2011	$520,078	$43,340
2012	$491,303	$40,942
2013	$462,528	$38,544
2014	$433,754	$36,146
2015	$404,979	$33,748
2016	$376,204	$31,350
2017	$347,429	$28,952
2018	$318,654	$26,554
2019	$289,879	$24,157
2020	$261,104	$21,759
2021	$232,329	$19,361

Assumptions in this forecast:

1. TransAlta capital structure as in 1996.
2. TransAlta cost of capital as in 1996.
3. Amortization of the contributions remains constant.
4. Income tax rates remain constant.
5. Mid-year convention applied to first year.

Rate Rider A2

Transmission Duplication Avoidance Adjustment

NOVA Chemical Corporation - Joffre Industrial System

Applicable to: NOVA Chemicals Corporation (NOVA Chemicals)

Available: To NOVA Chemicals' Joffre Industrial System, as designated by the AEUB Order No. HE 9826, for System Access Service to NOVA Chemicals at the 535S transmission station Point of Demand (POD) and Point of Supply (POS).

Rate: For each metering time interval, the Metered Demand and Metered Energy for the POS and POD at the 535S transmission station will be totalized for the purpose of billing under Rate DTS and Rate STS, as described in the Totalization section below. Charges under Rate DTS and Rate STS will be calculated using the totalized Metered Demand and the totalized Metered Energy. The meters to be totalized are 330 Line-1, 330 Line-2, 298L, 297L, 535ST1, and 535ST2.

NOVA Chemicals will make the following payments to the TA:

1. Capital Charge:
   A lump-sum payment of $2,375,000 to be made immediately upon implementation of this rate rider;

2. Incremental Losses Charge:
   Commencing on January 1, 2001, Metered Demand and Metered Energy will be adjusted through the metering balance calculation for the 535S transmission station, using the loss factors in the attached Schedule 1. If the Metered Demand in a metering interval is between two levels in Schedule 1, the applicable loss factor will be calculated by interpolating between the loss factors for the two levels of Metered Demand. If the Metered Demand in a metering interval is less than 10 MW, including 0 MW, the incremental loss will be deemed to be 0.14 MW. The meters to be compensated in the metering balancing calculation are on 298L, 297L, 535ST1, and 535ST2.

   For each billing period, commencing on the effective date of this rate rider, a payment equal to the totalized Metered Energy multiplied by the applicable loss factor and multiplied by the Pool Price, calculated on an hourly basis. The applicable loss factor for each hour will be the loss factor in the attached Schedule 1 that corresponds with the totalized Metered Energy for the hour; and

3. Other Expenses Charge:
   For each Billing Period commencing on January 1, 2001, an amount equal to the "Annual Payment" in the attached Schedule 2 for the applicable year, divided by 12.

Terms: All terms in the TA's 23 June Application for a Duplication Avoidance Tariff for NOVA Chemicals Corporation Joffre Industrial System will be applicable.

Metering and Totalizing[7]

If NOVA Chemicals were to build the Duplicate Facilities, the 535S transmission station would be a Point of Supply for metering when the Joffre Site power generation exceeds the load requirements. Likewise, it would be a Point of Demand when the Joffre Site generation does not meet the load requirements. The Duplication Avoidance Tariff will simulate this result by deeming the separate Point of Demand and Point of Supply at the 535S transmission station to be a single Point of Exchange for the purpose of totalizing Metered Demand and Metered Energy in applying the TA's Rate DTS and Rate STS.

During the Term of the Duplication Avoidance Tariff, the TA would totalize the metered data at the 535S transmission station for the load of NOVA Chemicals' Existing Facilities and the generation from its Cogeneration Facility. The totalized metered data would also include a debit to NOVA Chemicals to account for the deemed duplicate transformer losses. This would ensure that payments by NOVA Chemicals to the TA under Rate DTS and Rate STS are equivalent to the costs NOVA Chemicals would have incurred had they built the Duplicate Facilities.

The amount of load of the Existing Facilities included in the totalizing calculation would be limited to the deemed capacity of the duplicate transformer in NOVA Chemicals' Duplicate Facilities design, which is 80MVA. If the Metered Demand at the 535S transmission station for the Existing Facilities exceed this deemed capacity of 80 MVA, additional costs of upgrading the deemed duplicate transformer would be estimated and invoiced to NOVA Chemicals.

An example of the totalizing calculation follows.

Example of Totalizing[8]

The following is an example of the totalizing calculation for Metered Demand and Metered Energy for two different metering time intervals.

	Time Interval 1	Time Interval 2
535S Point of Demand (A)	+65 MW	+ 130
535S Point of Supply (B) (Co-generation Facility)	-365 MW	0 MW
Totalized Meter Demand and Energy (C)	- 300 MW	+ 130 MW

In Time Interval 1, under the Duplication Avoidance Tariff, NOVA Chemicals' demand requirement is 65 MW at the 535S transmission station. At the same time, NOVA Chemicals' Cogeneration Facility is delivering 365 MW of power to the AIES at the 535S transmission station. If NOVA Chemicals built the Duplicate Facilities, the Metered Energy delivered from

[7] Application, Section 2.5: Terms for the Duplication Avoidance Tariff; Section 2.5.1: Metering and Totalizing

[8] Application, Appendix C: Example of Totalizing0

the AIES for NOVA Chemicals' load requirement at point A would be zero MW, and the Metered Energy received by the AIES from the generator output at point B would be 300 MW. This energy balance is simulated by the proposed totalizing procedure. Combining the Point of Demand (A) and Point of Supply (B) produces a totalized Metered Demand of -300MW, where the negative sign signifies a net energy receipt by the AIES.

In Time Interval 2, the Cogeneration Facility is not operating, supplying zero MW of power, and NOVA Chemicals' load remains at 65 MW for the Existing Facilities and 65 MW for the new facilities. The result is a net load of +130 MW for that time interval, where the positive sign signifies a net energy delivery from the AIES.

Rider A2 Schedule 1

Incremental Loss Factors

Metered Demand of Existing Facilities (MW)	Loss Factor (% of Metered Demand of Existing Facilities)
$> 0 \leq 10$	1.41 %
$> 10 \leq 20$	0.76 %
$> 20 \leq 30$	0.57 %
$> 30 \leq 40$	0.49 %
$> 40 \leq 50$	0.46 %
$> 50 \leq 60$	0.45 %
$> 60 \leq 70$	0.45 %
$> 70 \leq 80$	0.47 %

Rider A2 Schedule 2
Other Expenses Charge

12 Month Period	Monthly Payment
Jan. 1, 2001 – Dec. 31, 2001	$ 2,142
Jan. 1, 2002 – Dec. 31, 2002	$ 2,107
Jan. 1, 2003 – Dec. 31, 2003	$ 2,179
Jan. 1, 2004 – Dec. 31, 2004	$ 2,152
Jan. 1, 2005 – Dec. 31, 2005	$ 2,234
Jan. 1, 2006 – Dec. 31, 2006	$ 4,013
Jan. 1, 2007 – Dec. 31, 2007	$ 2,162
Jan. 1, 2008 – Dec. 31, 2008	$ 3,283
Jan. 1, 2009 – Dec. 31, 2009	$ 2,204
Jan. 1, 2010 – Dec. 31, 2010	$ 3,219
Jan. 1, 2011 – Dec. 31, 2011	$ 2,131
Jan. 1, 2012 – Dec. 31, 2012	$ 5,305
Jan. 1, 2013 – Dec. 31, 2013	$ 2,185
Jan. 1, 2014 – Dec. 31, 2014	$ 2,141
Jan. 1, 2015 – Dec. 31, 2015	$ 11,723
Jan. 1, 2016 – Dec. 31, 2016	$ 4,343
Jan. 1, 2017 – Dec. 31, 2017	$ 2,151
Jan. 1, 2018 – Dec. 31, 2018	$ 4,745
Jan. 1, 2019 – Dec. 31, 2019	$ 2,211
Jan. 1, 2020 – Dec. 31, 2020	$ 6,835
Jan. 1, 2021 – Dec. 31, 2021	$ 2,264
Jan. 1, 2022 – Dec. 31, 2022	$ 2,225
Jan. 1, 2023 – Dec. 31, 2023	$ 2,172
Jan. 1, 2024 – Dec. 31, 2024	$ 7,790
Jan. 1, 2025 – Dec. 31, 2025	$ 2,417
Jan. 1, 2026 – Dec. 31, 2026	$ 2,184
Jan. 1, 2027 – Dec. 31, 2027	$ 2,300
Jan. 1, 2028 – Dec. 31, 2028	$ 2,256
Jan. 1, 2029 – Dec. 31, 2029	$ 2,197
Jan. 1, 2030 – Dec. 31, 2030	$ 36,105
Jan. 1, 2031 – Dec. 31, 2031	$ 2,273
Jan. 1, 2032 – Dec. 31, 2032	$ 5,154
Jan. 1, 2033 – Dec. 31, 2033	$ 2,340
Jan. 1, 2034 – Dec. 31, 2034	$ 2,291
Jan. 1, 2035 – Dec. 31, 2035	$ 2,440
Jan. 1, 2036 – Dec. 31, 2036	$ 7,595
Jan. 1, 2037 – Dec. 31, 2037	$ 2,310
Jan. 1, 2038 – Dec. 31, 2038	$ 2,239
Jan. 1, 2039 – Dec. 31, 2039	$ 2,386
Jan. 1, 2040 – Dec. 31, 2040	$ 4,518

Rate Rider A

Transmission Duplication Avoidance Rate A3

Shell Canada Corporation-Scotford Industrial System

Applicable to: Shell Canada Limited (Shell Canada)

Available: To Shell Canada's Scotford Industrial System, as designated by AEUB Order No. U2000-109 for System Access Service to Shell Canada at the 409S transmission station Point of Delivery (POD) and Point of Supply (POS).

Rate: For each metering time interval, the Metered Demand and Energy for each POS and POD (409ST1, 409ST2, 337S and 746L feeders) around the 409S transmission station will be synchronized, totalized and adjusted to measure electricity at the 138 kV bus for the purpose of billing under the Transmission Tariff. Charges under the Transmission Tariff will be calculated using the totalized Metered Demand and Energy.

Shell Canada will make the following payments to the TA:

1. Capital Charge:
   A payment of $2,907,800 is due immediately upon implementation of this rate rider.

2. Incremental Losses Charge:
   Commencing on the effective date of this rate rider, Metered Demand and Metered Energy will be adjusted through the metering balancing calculation for the 409S transmission station, using the loss factors in the attached Schedule 1. If the Metered Demand in a metering interval is between two levels in Schedule 1, the applicable loss factor will be calculated by interpolating between the loss factors for the two levels of Metered Demand. If the Metered Demand in a metering interval is less than 10 MW, including 0 MW, the incremental loss will be deemed to be 0.083 MW. The meters to be compensated in the metering balancing calculation are on 409ST1, 409ST2, 337S and 746L.

   For each billing period, commencing on the effective date of this rate rider, a payment equal to the totalized Metered Energy multiplied by the applicable loss factor and multiplied by the Pool Price, calculated on an hourly basis. The applicable loss factor for each hour will be the loss factor in the attached Schedule 1 that corresponds with the totalized Metered Energy for the hour; and

3. Other Expenses Charge:
   The Other Expenses Charge is shown in the attached Schedule 2.

   Shell Canada will receive a Customer-Owned Transmission Station Credit in respect of the Duplicate Facilities as is provided to other DTS customers of the

TA who provide their own Transmission Station, pending the decision of the Board on the TA's 2002 tariff application.

Term: All Terms and Conditions in the Transmission Administrator's Tariff apply in addition to the terms in this Application for a Duplication Avoidance Tariff for Shell Canada's Scotford Industrial System. If either the TA or Shell Canada were to terminate the Duplication Avoidance Tariff at a future date, Shell Canada would receive a partial refund of the lump sum Capital Charge payment. The amount of the partial refund would be the deemed remaining undepreciated dollar amount of the avoided Duplicate Facilities, in the year that the TA or Shell Canada gives notice to terminate the Duplication Avoidance Tariff. The undepreciated dollar value would be calculated based on the lump sum Capital Charge payment using a straight-line depreciation over the first 24 years of the Term of the Duplication Avoidance Tariff. At the end of 24 years, the undepreciated value would be zero. The termination notice period, for both the TA and Shell Canada, will be 24 months.

Metering & Totalizing

Totalization should proceed on the basis of economic indifference to Shell Canada between the DAT and the construction of Duplicate Facilities and a net positive benefit to other transmission customers. These principles are met by the terms proposed for the Duplication Avoidance Tariff.

There is no direct relationship between the size of 409S (sized for a prior, smaller load-only Scotford site) and the larger scale operations now reflected in the industrial system. The Duplication Avoidance Tariff for 409S is the most advantageous arrangement for the TA compared to construction of Duplicate Facilities.

If Shell Canada were to build the Duplicate Facilities, the 409S transmission station would be a Point of Supply when the Scotford Site power generation exceeds the load requirements. Likewise, it would be a Point of Delivery when the Scotford Site generation does not meet the load requirements. The Duplication Avoidance Tariff will simulate this result by deeming the separate Point of Delivery and Point of Supply at the 409S transmission station to be a single Point of Exchange for the purpose of totalizing Metered Demand and Metered Energy.

During the Term of the Duplication Avoidance Tariff, the TA would totalize the metered data at the 409S transmission station for the load of Shell Canada's Load Facilities and the generation from its Cogeneration Facility. This would ensure that payments by Shell Canada to the TA under the TA's Tariff are equivalent to the costs that Shell Canada would have incurred had they built the Duplicate Facilities.

The level of load of the Load Facilities included in the totalization calculation would be limited to the deemed capacity of the Duplicate Facilities in Shell Canada's Duplicate Facilities design. Given that the capacity of the Duplicate Facilities would be identical to that of the 409S transmission station, if the transformer requires upgrading in order to serve additional load from the Load Facilities, Shell Canada will be responsible for the cost of the upgrade.

Example of Totalizing

The following is an example of the totalizing calculation for Metered Demand and Metered Energy for two different metering time intervals.

	Time Interval 1	Time Interval 2
409S Point of Demand (A)	+60 MW	+60 MW
409S Point of Supply/ Point of Demand (B)	-70 MW	+20 MW
Totalized Metered Demand and Energy (C)	-10 MW	+80 MW

In Time Interval 1, under the Duplication Avoidance Tariff, Shell Canada's load requirement is 60 MW from the 409S transmission station. At the same time, Shell Canada's Cogeneration Facility is delivering a net supply of 70 MW to the AIES at the 409S transmission station. This is net of load directly served from the Cogeneration Facility downstream of the 409S. If Shell Canada built the Duplicate Facilities, the level of energy delivered from Shell Canada to the AIES would be 10 MW. This energy balance is simulated through the proposed totalizing procedure. Combining the Point of Demand (A) and Point of Supply (B) produces a totalized Metered Demand of –10 MW, where the negative sign signifies a net energy receipt by the AEIS.

In time Interval 2, the load served from Point of Demand (A) remains at 60 MW but there is a reduced supply of energy from the Cogeneration Facility. Due to load requirements directly served from the Cogeneration Facility (net of partial load shedding), energy flows at (B) are reversed, resulting in 20 MW of energy delivered from the AIES to Shell Canada. Thus (B) is also a Point of Demand. If Shell Canada built the Duplicate Facilities, the level of energy delivered from the AIES to Shell Canada at (A) and (B) would be 80 MW. Through the proposed totalizing procedure the totalized Metered Demand would be +80 MW, where the positive sign signifies a net energy delivery from the AEIS to Shell Canada.

Rider A3 Schedule 1

Incremental Loss Factors

Metered Demand of Load Facilities (MW)	Loss Factor (% of Metered Demand of Load Facilities)
> 0 ≤ 10	0.84%
> 10 ≤ 20	0.46%
> 20 ≤ 30	0.35%
> 30 ≤ 40	0.31%
> 40 ≤ 50	0.30%
> 50 ≤ 60	0.30%
> 60 ≤ 70	0.30%
> 70 ≤ 80	0.32%
> 80 ≤ 90	0.33%
> 90 ≤ 100	0.35%

Rider A3 Schedule 2

Other Expenses Charge

12 Month Period	Monthly Payment
Jan. 1, 2002 – Dec. 31, 2002	$ 1,779
Jan. 1, 2003 – Dec. 31, 2003	$ 1,673
Jan. 1, 2004 – Dec. 31, 2004	$ 1,723
Jan. 1, 2005 – Dec. 31, 2005	$ 1,669
Jan. 1, 2006 – Dec. 31, 2006	$ 1,820
Jan. 1, 2007 – Dec. 31, 2007	$ 3,405
Jan. 1, 2008 – Dec. 31, 2008	$ 1,655
Jan. 1, 2009 – Dec. 31, 2009	$ 4,055
Jan. 1, 2010 – Dec. 31, 2010	$ 1,701
Jan. 1, 2011 – Dec. 31, 2011	$ 4,264
Jan. 1, 2012 – Dec. 31, 2012	$ 1,626
Jan. 1, 2013 – Dec. 31, 2013	$ 4,954
Jan. 1, 2014 – Dec. 31, 2014	$ 1,605
Jan. 1, 2015 – Dec. 31, 2015	$ 1,637
Jan. 1, 2016 – Dec. 31, 2016	$ 16,504
Jan. 1, 2017 – Dec. 31, 2017	$ 5,665
Jan. 1, 2018 – Dec. 31, 2018	$ 1,737
Jan. 1, 2019 – Dec. 31, 2019	$ 4,222
Jan. 1, 2020 – Dec. 31, 2020	$ 1,807
Jan. 1, 2021 – Dec. 31, 2021	$ 15,946
Jan. 1, 2022 – Dec. 31, 2022	$ 1,954
Jan. 1, 2023 – Dec. 31, 2023	$ 1,918
Jan. 1, 2024 – Dec. 31, 2024	$ 1,956
Jan. 1, 2025 – Dec. 31, 2025	$ 9,933
Jan. 1, 2026 – Dec. 31, 2026	$ 2,265
Jan. 1, 2027 – Dec. 31, 2027	$ 2,076
Jan. 1, 2028 – Dec. 31, 2028	$ 2,201
Jan. 1, 2029 – Dec. 31, 2029	$ 2,160
Jan. 1, 2030 – Dec. 31, 2030	$ 2,203
Jan. 1, 2031 – Dec. 31, 2031	$ 59,074
Jan. 1, 2032 – Dec. 31, 2032	$ 2,292
Jan. 1, 2033 – Dec. 31, 2033	$ 7,777
Jan. 1, 2034 – Dec. 31, 2034	$ 2,479
Jan. 1, 2035 – Dec. 31, 2035	$ 2,432
Jan. 1, 2036 – Dec. 31, 2036	$ 2,761

Rate Rider A4

Transmission Duplication Avoidance Adjustment

Imperial Oil Resources Limited – Cold Lake Industrial System

Applicable to: Imperial Oil Resources Limited (Imperial Oil)

Available: To Imperial Oil's Cold Lake Industrial System, as designated by AEUB Order No. HE 9901, plus any expansions to this Industrial System as may be approved by the AEUB, for System Access Service to Imperial Oil at the 715S transmission station Point of Demand and Point of Supply and the 837S transmission station Point of Demand.

Rate: For each metering time interval, the Metered Demand and Metered Energy for the POS and PODs, at the 837S and 715S transmission stations, will be totalized for the purpose of billing under Rate DTS and Rate STS, as described in the TA's June 22, 2001 Application for a Duplication Avoidance Tariff for Imperial Oil Resources Limited Cold Lake Site. Charges under Rate DTS and Rate STS will be calculated using the totalized Metered Demand and the totalized Metered Energy. The meters at the 837S transmission station to be totalized are 5L408, 5L409, and 5L410. The meters at the 715S transmission station to be totalized are 5L242, 5L335, 5L367, 5L395, and the future metering point for Imperial Oil's Cogeneration Facility.

Imperial Oil shall make the following payments to the TA:

1. Capital Charge:
   A lump-sum payment of $5,968,800 to be made immediately upon implementation of this rate rider;

2. Incremental Losses Charge:
   For each billing period, commencing on the effective date of this rate rider, a payment equal to the totalized Metered Energy multiplied by the applicable loss factor and multiplied by the Pool Price, calculated on an hourly basis. The applicable loss factor for each hour will be the loss factor in the attached Schedule 1 that corresponds with the totalized Metered Energy for the hour; and

3. Other Expenses Charge:
   For each Billing Period, commencing on the effective date of this rate rider, an amount equal to the "Monthly Payment" in the attached Schedule 2 for the applicable year.

Terms: All terms in the TA's June 22, 2001 Application for a Duplication Avoidance Tariff for Imperial Oil Resources Limited Cold Lake Site will be applicable.

Metering and Totalizing

If Imperial Oil were to build the Duplicate Facilities, the Leming Lake transmission station would be a Point of Supply when the Cold Lake Site power generation exceeds the load requirements, and a Point of Demand when the generation does not meet the load requirements. The Duplication Avoidance Tariff will simulate these conditions by deeming the Points of Demand at the Mahihkan and Leming Lake transmission stations, and the Point of Supply at the Leming Lake transmission station, to be a single Point of Connection for the purpose of totalizing Metered Demand and Metered Energy in applying Rates DTS and STS.

During operation of the Duplication Avoidance Tariff, the TA will totalize the metered data for Imperial Oil's load and generation served from the Mahihkan and Leming Lake transmission stations. This will ensure that payments by Imperial Oil to the TA under Rate DTS and Rate STS are equivalent to the costs Imperial Oil would have incurred for the Duplicate Facilities.

The amount of load included in the totalizing calculation will be limited to 115 MW, which is the maximum amount of load that the Duplicate Facilities would be able to serve, based on the deemed capacity of the duplicate transmission line in Imperial Oil's design. If the combined Metered Demand at the Mahihkan and Leming Lake transmission stations for the Load Facilities exceeds the 115 MW limit, the costs that would have been required to service the additional load under the Duplicate Facilities alternative will be estimated and invoiced to Imperial Oil.

Example of Totalizing

The following is an example of the totalizing calculation for Metered Demand and Metered Energy for two different metering time intervals.

	Time Interval 1	**Time Interval 2**
Point of Demand (A)(Mahihkan)	+45 MW	+45 MW
Point of Supply / Point of Demand (B)(Leming Lake)	-100 MW	+60 MW
Totalized Metered Demand and Energy (C)	-55 MW	+105 MW

In Time Interval 1, under the Duplication Avoidance Tariff, Imperial Oil's demand requirement is 45 MW at each of the Mahihkan and Leming Lake transmission stations. At the same time, Imperial Oil's Cogeneration Facility is producing 160 MW of power, of which 15 MW is used to directly serve other load requirements. The net delivery to the AIES is 145 MW at the Leming Lake transmission station. If Imperial Oil built the Duplicate Facilities, the Metered Energy delivered by the AIES to Imperial Oil's load requirement at the Mahihkan transmission station would be zero, and the Metered Energy received by the AIES from the generator output at the Leming Lake transmission station would be 55 MW (160 MW of generation minus 105 MW of load). This energy balance is simulated by the proposed totalizing procedure. Combining the Point of Demand (A) and Point of Supply (B) produces an adjusted Metered Demand of -55 MW, where the negative sign signifies a net energy receipt by the AIES.

In Time Interval 2, the Cogeneration Facility is not operating and Imperial Oil's load remains at 105 MW (45 MW at the Mahihkan station, and 45 MW plus 15 MW at Leming Lake station).

The result is a net load of +105 MW for that time interval, where the positive sign signifies a net energy delivery from the AIES.

Rider A4 Schedule 1

Incremental Loss Factors

Metered Demand of Load Facilities (MW)	Loss Factor (% of Metered Demand of Load Facilities)
$> 0 \leq 10$	1.88%
$> 10 \leq 20$	1.31%
$> 20 \leq 30$	0.64%
$> 30 \leq 40$	0.54%
$> 40 \leq 50$	0.60%
$> 50 \leq 60$	0.73%
$> 60 \leq 70$	0.90%
$> 70 \leq 80$	1.09%
$> 80 \leq 90$	1.29%
$> 90 \leq 100$	1.51%
$> 100 \leq 110$	1.72%
$> 110 \leq 115$	1.91%

Rider A4 Schedule 2
Other Expenses Charge

12 Month Period	Monthly Payment
Jan. 1, 2003 – Dec. 31, 2003	$ 4,223
Jan. 1, 2004 – Dec. 31, 2004	$ 6,323
Jan. 1, 2005 – Dec. 31, 2005	$ 4,286
Jan. 1, 2006 – Dec. 31, 2006	$ 4,225
Jan. 1, 2007 – Dec. 31, 2007	$ 5,791
Jan. 1, 2008 – Dec. 31, 2008	$ 7,651
Jan. 1, 2009 – Dec. 31, 2009	$ 5,189
Jan. 1, 2010 – Dec. 31, 2010	$ 6,835
Jan. 1, 2011 – Dec. 31, 2011	$ 4,500
Jan. 1, 2012 – Dec. 31, 2012	$ 8,367
Jan. 1, 2013 – Dec. 31, 2013	$ 4,457
Jan. 1, 2014 – Dec. 31, 2014	$ 10,648
Jan. 1, 2015 – Dec. 31, 2015	$ 5,059
Jan. 1, 2016 – Dec. 31, 2016	$ 5,430
Jan. 1, 2017 – Dec. 31, 2017	$ 19,466
Jan. 1, 2018 – Dec. 31, 2018	$ 10,660
Jan. 1, 2019 – Dec. 31, 2019	$ 4,765
Jan. 1, 2020 – Dec. 31, 2020	$ 10,594
Jan. 1, 2021 – Dec. 31, 2021	$ 5,565
Jan. 1, 2022 – Dec. 31, 2022	$ 29,055
Jan. 1, 2023 – Dec. 31, 2023	$ 5,799
Jan. 1, 2024 – Dec. 31, 2024	$ 5,905
Jan. 1, 2025 – Dec. 31, 2025	$ 5,366
Jan. 1, 2026 – Dec. 31, 2026	$ 19,095
Jan. 1, 2027 – Dec. 31, 2027	$ 6,492
Jan. 1, 2028 – Dec. 31, 2028	$ 5,695
Jan. 1, 2029 – Dec. 31, 2029	$ 5,962
Jan. 1, 2030 – Dec. 31, 2030	$ 7,811
Jan. 1, 2031 – Dec. 31, 2031	$ 6,043

Rate Rider B

Working Capital Deficiency/Surplus Rider

Purpose: The Working Capital Deficiency/Surplus Rider is to recover unexpected increases in the TA's working capital deficiency or to refund unexpected surplus of working capital.

Applicable to: Customers receiving service under the following Rate Schedules:

DTS
STS

Effective: The rider will be invoked for the current Billing Period when, on the last Business Day of the current Billing Period:

- the TA's working capital balance either exceeds or falls short of the TA's annual average forecast by an amount equal to or greater than $7.0 Million.

Rate: A percentage increase or decrease, that when invoked will restore the TA's working capital deficiency to the TA's annual average forecast, applied to charges under the rate schedules listed above in the current Billing Period.

Terms: The Terms and Conditions form part of this Rate Schedule.

Rate Rider C

Deferral Account Adjustment Rider

Purpose: To recover or refund all accumulated deferral account balances.

Applicable to: Customers receiving service under the following Rate Schedules:

DTS
STS

Effective: The rider is effective for all billing periods.

Rate: A $/MWh increase or decrease designed to restore the deferral account balances to zero over the following calendar quarter or such longer period as determined by the TA to minimize rate impact.

Terms: The Terms and Conditions form part of this Rate Schedule.

Rate Rider D

Transmission Administrator Tariff Deficiency Correction Regulation Rider

Purpose: To recover the amounts set out in the Transmission Administrator Tariff Deficiency Correction Regulation.

Applicable to: Customers receiving service under the following Rate Schedules:

DTS
STS

Effective: The rider is effective from January 1, 2003 to May 31, 2003 inclusive.

Rate: Charges for STS customers in any one Billing Period shall be,

$0.095/MWh of Metered Energy during the Billing Period.

Charges for DTS customers in any one Billing Period shall be,
$38.95/MW/month of Billing Capacity in the Billing Period, plus
$0.054/MWh of Metered Energy during the Billing Period.

Billing Capacity shall be the highest of:
(i) The highest fifteen (15) minute Metered Demand in the Billing Period;
(ii) The Ratchet Level; or
(iii) 90% of the Contract Capacity.

where "Ratchet Level" is defined as the highest of the following:

(i) 90% of the highest Metered Demand in the past 12 months;
(ii) 85% of the highest Metered Demand in the past 24 months;
(iii) 80% of the highest Metered Demand in the past 36 months;
(iv) 75% of the highest Metered Demand in the past 48 months;
(v) 70% of the highest Metered Demand in the past 60 months.

Terms: The rate is separately applicable at each POS and POD.

References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with paragraphs 6.2 and 6.3 of the Terms and Conditions

The Terms and Conditions form part of this Rate Schedule.

APPENDIX B

Maximum Continuous Rating Values for Regulated Generation Units under Rate STS

GENERATING UNIT	UNIT MCR(MW)	POINT OF SUPPLY TOTAL
ATCO Battle River 1		
ATCO Battle River 2		
ATCO Battle River 3	147.3	
ATCO Battle River 4	147.3	
ATCO Battle River 5	368.2	
ATCO Battle River		662.8
ATCO H. R. Milner	144.3	144.3
ATCO Rainbow 1	25.9	
ATCO Rainbow 2	39.8	
ATCO Rainbow 3	21.4	
ATCO Rainbow		87.1
ATCO Sheerness 1	189.1 **ATCO**/189.1 **TAU**	
ATCO Sheerness 2	189.1 **ATCO**/189.1 **TAU**	
ATCO Sheerness		756.4
EPI Clover Bar 1	157.2	
EPI Clover Bar 2	157.2	
EPI Clover Bar 3	157.2	
EPI Clover Bar 4	157.2	
EPI Clover Bar		628.8
EPI Genesee 1	384.1	
EPI Genesee 2	384.1	
EPI Genesee		768.2
EPI Rossdale 8	66.7	
EPI Rossdale 9	70.6	
EPI Rossdale 10	70.6	
EPI Rossdale		207.9
TAU Hydro	791.4	791.4
TAU Sundance 1	278.6	
TAU Sundance 2	278.6	
TAU Sundance 3	353.2	
TAU Sundance 4	353.2	
TAU Sundance 5	353.2	
TAU Sundance 6	364.2	
TAU Sundance		1981.0
TAU Wabamun 1	63.7	
TAU Wabamun 2	63.7	
TAU Wabamun 3	139.3	
TAU Wabamun 4	278.6	
TAU Wabamun		545.3
TAU Keephills 1	381.1	
TAU Keephills 2	381.1	
TAU Keephills		**762.2**
TOTAL		**7335.4**

APPENDIX 4

APPENDIX 4

2004 GTA Stakeholder Issues

1. Long range transmission planning and major transmission advancement.
2. Evaluation of future need for IBOC and LBC SO capacity in the Calgary area.
3. Loss factor audit methodology.
4. Reactive power market.
5. Reliability criteria, standards and process.
6. Customer contribution issues other than COS/COT related issues.
7. The need for revisions to the ISO's tariff Terms and Conditions of Service.
8. ISO incentive plans.
9. Resolution of Board Directives not addressed by the Board in is decision respecting the ISO's 2003 GTA.

Revised Total Revenue Requirement

TA 2002 and 2003 Revenue Requirement
($ millions)

	2003 Forecast	2002 Approved	2002 Actual[1]
Wires Costs			
ATCO Electric Ltd.	132.6	120.6	120.4
City of Lethbridge	2.8	2.8	2.8
City of Red Deer	1.8	1.8	1.8
ENMAX Power Corporation	34.4	27.9[2]	27.6
EPCOR Transmission Inc.	34.0	34.0	34.0
TransAlta	2.7	164.9	55.0
Aquila Networks (Farm)	1.9	1.3	1.3
AltaLink	133.3	Not Applicable[3]	109.9
Subtotal Wires	**343.5**	**353.0**	**352.8**
Foster Creek Substation (ATCO Utilities Services)	1.4	1.4	1.4
Credits (IBOC)	2.7	8.3	2.9
Credits (LBC SO)	3.9	0.4	0.2
Capital Additions	1.1	12.3	2.4
Isolated Generation	(6.1)	12.7	12.8
Total Wires	**346.5**	**388.5**	**372.6**
Ancillary Services Costs			
Operating Reserves			
Regulating	48.2	49.0	41.1
Spinning	49.3	63.5	53.0
Supplemental	24.7	23.6	22.7
Standby	44.8	8.9	39.0
Subtotal Reserves	**167.0**	**145.0**	**155.8**
Under Frequency Mitigation	5.2	5.3	5.0
Transmission Must Run	26.1	16.7	55.5[4]
Fort Saskatchewan Load Shed	0.9	0.8	0.8
Hydro Motoring	4.2	4.2	4.2

[1] The 2002 actual costs represent actual costs to the end of November 2002 and a forecast of costs for December 2002.

[2] This includes an approved revenue requirement of $27.6M plus $0.3M for the Beddington Substation.

[3] The 2002 interim approved wire costs for AltaLink are included in the TransAlta amounts for 2002.

[4] The 2002 actual costs for transmission must run reflect invoiced amounts and incorporate changes arising from Board Decision 2002-103.

TA 2002 and 2003 Revenue Requirement
($ millions)

	2003 Forecast	2002 Approved	2002 Actual[1]
Subtotal	**36.4**	**27.0**	**65.5**
Remedial Action Schemes	0.4	0.7	0.4
Black Start	2.2	1.5	1.5
Subtotal RAS/Black Start	**2.6**	**2.2**	**1.9**
ILRAS	0.5	0.7	0.4
Poplar Hill	1.9	1.8	1.8
Total Ancillary Services Costs	**208.4**	**176.7**	**225.4**
Losses			
Pool Payment	142.7	164.9	114.8
Losses Studies Surcharge	0.0	0.7	0.7
Total Losses	**142.7**	**165.6**	**115.5**
Other Industry Costs			
System Controller Shared Costs	3.6	3.4	3.4
Regulatory Hearing Costs	9.8	1.0	2.2
WECC	1.0	1.1	1.0
TA Share of Board Overhead	1.6	Not Applicable	1.6
Total Other Industry Costs	**16.0**	**5.5**	**8.2**
TA Costs			
Administration Costs	12.9	12.0	12.4
Interest, Return on Investment & Amortization and Depreciation	1.6	2.0	(0.5)
Management Fee	0.0	4.8	4.4
ISO Transition Costs	1.2	Not Applicable	Not Applicable
Tariff Def. Cor. Regulation Fee	4.9	Not Applicable	Not Applicable
Total TA Costs	**20.6**	**18.8**	**16.3**
TOTAL REVENUE REQUIREMENT	**734.3**	**755.1**	**738.0**

Revised Attachment 7 (Phase 2) to the 2003 General Tariff Application

Tariff Rate Calculations

Assumptions	**All Hours**	**Units**
Energy Supplied	53,785,080	MWh
Energy Consumed	50,902,213	MWh
Average Pool Price	47.93	$/MWh
Demand MW-Months	107,137.0	MW-months
Regulated Supply MW-Months	88,024.8	MW-months

Wires Costs, TA Costs, and Other Industry Costs	383.2		M$
58% allocation to load customers	→ 222.3		M$
less: load-related opportunity revenues	0.7		M$
equals net load-related wires cost	223		M$
60% demand-related	→ 133.8		M$
divided by Demand MW-Months	107,137.0		MW-months
DTS Wires Demand Charge	**1,248.62**		$/MW/month
40% energy-related	→ 89.2		M$
divided by All Hours Energy Consumed	50,902,213		
DTS Wires Energy Charge	**$ 1.75**		$/MWh
42% allocation to supply customers	→ 160.9		M$
less: supply-related opportunity revenue	-4.0		M$
less: local generation connection cost	-30.6		M$
equals net supply-related wires cost	126.3		M$
100% energy-related	→ 126.3		M$
divided by All Hours Energy Supplied	53,785,080		MWh
STS Wires Energy Charge	**2.35**		$/MWh
local generation connection assets	→ 30.6		M$
divided by Regulated Supply MW-Months	88,024.8		MW-months
Regulated Generating Unit Connection Charge	**348**		$/MW/month
System Support Services	169.6		M$
50% allocated to supply customers, 100% energy-related	→ 84.8		M$
STS System Support Services (SSS) Charge	**3.289% x MWh x Pool Price**		
50% allocated to load customers, 100% energy-related	→ 84.8		
DTS System Support Services (SSS) Charge	**3.476% x MWh x Pool Price**		
Voltage Control, TMR/SMR, Under Frequency Mitigation, and Hydro Motoring	36.4		
50% allocated to supply customers, 100% energy-related	→ 18.2		
less power factor incentive charge	0		
equals	18.2 →	18.2	
STS Voltage Control Charge	**0.706% x MWh x Pool Price**		
50% allocated to load customers, 100% energy-related	→ 18.2		
DTS Voltage Control Charge	**0.75% x MWh x Pool Price**		
Voltage Control - Poplar Hill	1.9		
100% allocated to load customers, 100% demand-related	→ 1.9		
divided by Demand MW-Months	107,137.0		
DTS Poplar Hill Charge	**17.73**		$/MW/month
Remedial Action Schemes (including ILRAS)	0.5		
100% allocated to load customers	→ 0.5		
60% demand-related	→ 0.3		
divided by Demand MW-Months	107,137.0		
DTS RAS Demand Charge	**2.80**		$/MW/month
40% energy-related	→ 0.2		
divided by All-Hours Energy Consumed	50,902,213		
DTS RAS Variable Charge	**0.0039**		$/MWh

Rate Schedule – Demand Transmission Service (DTS)

Applicable to: Demand Customers

Rate: Charges for the DTS in any one Billing Period shall be the sum of the Interconnection Charge, the Operating Reserve Charge and the Other System Support Services Charge, where:

The Interconnection Charge equals:

$1,248.62 /MW/month of Billing Capacity in the Billing Period, plus
$1.75/MWh of Metered Energy during the Billing Period.

Billing Capacity shall be the highest of:
(i) The highest fifteen (15) minute Metered Demand in the Billing Period;
(ii) The Ratchet Level; or
(iii) 90% of the Contract Capacity.

where "Ratchet Level" is defined as the highest of the following:

(i) 90% of the highest Metered Demand in the past 12 months;
(ii) 85% of the highest Metered Demand in the past 24 months;
(iii) 80% of the highest Metered Demand in the past 36 months;
(iv) 75% of the highest Metered Demand in the past 48 months;
(v) 70% of the highest Metered Demand in the past 60 months.

The Operating Reserve Charge equals:

Metered Energy in each hour X 4.22% X Pool Price.

The Other System Support Services Charge equals:

$20.53/MW/month of highest Metered Demand in the Billing Period, plus a charge (where Power Factor is less than 90%) of $400/MVA applied to the difference between the highest metered Apparent Power and 111% of the highest Metered Demand during the same Billing Period.

Terms: The rate is separately applicable at each POD.

References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with paragraphs 6.2 and 6.3 of the Terms and Conditions.

The Terms and Conditions form part of this Rate Schedule.
Rate Riders A&B apply to these customers when invoked by the TA.

Rate Schedule – Export Service (ES)

Applicable to: Customers exporting electric energy from the AIES.

Available: When sufficient transmission capacity exists to accommodate the capacity scheduled for service, and this service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Export Service.

Rate: The charges for service per Billing Period shall be as follows:

(1) The greater of (a) and (b) below:

$2.35/MWh of Energy Transfer during the Billing Period; plus

Incremental Losses Charge, calculated as the sum, over all transaction hours in the Billing Period of the following:

Energy Transfer in hour x location specific loss factor x Pool Price for the hour, where the location specific loss factor is an incremental factor determined by the TA for each Point of Exchange.

A minimum charge, calculated as the sum, over all transactions in the Billing Period, of the following (where capacity scheduled is the hour-ahead scheduled amount for the transaction):

75% x capacity scheduled for Customer for the transaction x hours in the transaction x ($2.33/MWh + Incremental Losses Charge / Energy Transfer in Billing Period)

Plus

An Operating Reserve charge or other System Support Service charge when, in the opinion of the TA, the transaction requires the procurement of incremental System Support Services and/or Operating Reserve.

Plus

Transaction Fee: $500 per Billing Period.

Terms: System Access Service provided pursuant to this Rate Schedule is recallable on one (1) hour's notice. The rate is separately applicable at each Point of Exchange.

The Terms and Conditions form part of this Rate Schedule.

Rate Schedule – Supply Transmission Service (STS)

Applicable to: Customers who supply electrical energy to the AIES from within Alberta.

Rate: Charges for STS in any one Billing Period shall be the sum of the Interconnection Charge, the Losses Charge, and the Operating Reserve Charge, where:

The Interconnection Charge equals:

$2.35/MWh of Metered Energy during the Billing Period.

For the purpose of calculating the Interconnection Charge under this STS Rate Schedule Metered Energy shall be measured on a 15-minute interval.

The Losses Charge equals:

Metered Energy in each hour X location specific loss factor X Pool Price

Where "location specific loss factor" is determined by the Transmission Administrator for each Customer.

For the purpose of calculating the Losses Charge under this STS Rate Schedule Metered Energy shall be measured on a 15-minute interval.

Operating Reserves Charge equals:

Metered Energy in each hour X 4.0% X Pool Price.

Regulated Generating Unit Connection Costs:

An additional charge of $348/MW per month for each MW of unit MCR applicable only to regulated generating units, as that term is defined in the Act, as outlined in Appendix B of the rate schedules.

Terms: The rate is separately applicable at each POS.

References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with paragraphs 6.2 and 6.3 of the Terms and Conditions.

The Terms and Conditions form part of this Rate Schedule.
Rate Riders A&B apply to these customers when invoked by the TA.

Rate Schedule – Import Service (IS)

Applicable to: Customers importing electric energy into the AIES.

Available: When sufficient transmission capacity exists to accommodate the capacity scheduled for service, and this service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Import Service.

Rate: The charges for service per Billing Period shall be as follows:

(8) The greater of (a) or (b) below:

(a)

(i) $2.35/MWh of Energy Transfer during the Billing Period;

(ii) Incremental Losses Charge, calculated as the sum, over all transaction hours in the Billing Period of the following:

Energy Transfer in hour x location specific loss factor x Pool Price for the hour, where the location specific loss factor is an incremental factor determined by the TA for each Point of Exchange.

(b) A minimum charge, calculated as the sum, over all transactions in the Billing Period, of the following (where capacity scheduled is the hour-ahead scheduled amount for the transaction):

75% x capacity scheduled for Customer for the transaction x hours in the transaction x ($2.33/MWh + Incremental Losses Charge/Energy Transfer in the Billing Period)

Plus

(9) An Operating Reserve charge or other System Support Service charge when, in the opinion of the TA, the transaction requires the procurement of incremental System Support Services and/or Operating Reserve.

Plus

(10) Transaction Fee: $500 per Billing Period.

Terms: System Access Service provided pursuant to this Rate Schedule is recallable on one (1) hour's notice.

The rate is separately applicable at each Point of Exchange.

The Terms and Conditions form part of this Rate Schedule.